2019 Assessment of the ISO New England Electricity Markets

POTOMAC ECONOMICS

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PREFACE

Potomac Economics serves as the External Market Monitor for ISO-NE. In this role, we are responsible for evaluating the competitive performance, design, and operation of the wholesale electricity markets operated by ISO-NE.[1] In this assessment, we provide our annual evaluation of the ISO's markets for 2019 and our recommendations for future improvements. This report complements the Annual Markets Report, which provides the Internal Market Monitor's evaluation of the market outcomes in 2019.

We wish to express our appreciation to the Internal Market Monitor and other staff of the ISO for providing the data and information necessary to produce this report.

1 The functions of the External Market Monitor are listed in Appendix III.A.2.2 of "Market Rule 1."

EXECUTIVE SUMMARY

ISO-NE operates competitive wholesale markets for energy, operating reserves, regulation, financial transmission rights ("FTRs"), and forward capacity to satisfy the electricity needs of New England. These markets provide substantial benefits to the region by coordinating the commitment and dispatch of the region's resources to ensure that the lowest-cost supplies are used to reliably satisfy demand in the short-term. At the same time, the markets establish transparent, efficient price signals that govern long-term investment and retirement decisions.

The ISO Internal Market Monitor ("IMM") produces an annual report that provides an excellent summary and discussion of the market outcomes and trends during the year.[2] The IMM Annual Report shows:

- Energy prices fell roughly 30 percent from 2018 to 2019 as natural gas prices decreased by 34 percent. This correlation is consistent with our finding that the market performed competitively because energy offers in competitive markets should track input costs.
- Load fell 4 percent on average from 2018 to 2019, which was primarily attributable to milder winter and summer weather conditions. Aside from weather-related variations, load levels have been on a downward trend in recent years because of the increase in energy efficiency and growth in behind-the-meter solar generation.
- The market was never short of operating reserves in 2019 partly because of the low load levels and mild summer and winter peak conditions. Therefore, no Pay-for-Performance ("PFP") settlements occurred.
- The capacity compensation rate was $9.55 per kW-month in the 2018/19 Capacity Commitment Period ("CCP") and $7.03 per kW-month in the 2019/20 CCP.
  - These relatively high levels reflect that the peak load forecasts for the FCAs held in 2015 and 2016 were significantly higher than the actual peak load level in 2019.
  - The capacity compensation rate will continue to fall through the 2023/24 CCP when it will reach $2 per kW-month because of: (a) downward revisions in load forecasts; and (b) the retention of the Mystic CCs under a cost-of-service agreement.

The IMM report provides detailed discussion of these trends and other market results and issues that arose in the ISO-NE markets during 2019. This report is intended to complement the IMM report, comparing key market outcomes with other RTO markets, evaluating the competitive performance of the markets, and focusing on key market design. This report addresses long-term economic incentives and integration of state initiatives to promote investment in renewable resources, reliability commitments, the efficiency of the PFP framework.

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2 See ISO New England's Internal Market Monitor 2019 Annual Markets Report, available at https://www.iso-ne.com/markets-operations/market-monitoring-mitigation/internal-monitor.

Cross-Market Comparison of Key Market Outcomes

We compare several key market outcomes in the ISO-NE markets to comparable outcomes and metrics in other RTO markets in Section I of this report and find that:

- ISO-NE generally exhibited the highest energy prices of the RTO markets in recent years because of higher natural gas prices in this region. One exception was ERCOT, which operates an "energy-only" market and saw a sharp increase in energy prices in 2019 driven by operating reserve shortages priced at $9,000 per MWh in the summer because of high temperatures and low installed reserve margins. ISO-NE also has strong shortage pricing through the PFP framework, but experienced no shortages in 2019.
- ISO-NE experiences far less congestion than other RTOs. On a per MWh of load basis, the average congestion cost in New England has been less than $0.40 in the last four years, which was one-tenth to one-fifth of the congestion levels in other RTO markets.
  - This reflects that large transmission investments have been made over the past decade, resulting in transmission service cost of more than $17 per MWh – well more than double the average rates in other RTO markets.
  - Transmission investments in ISO-NE have generally been made to satisfy relatively aggressive local reliability planning criteria, while the primary reasons for transmission expansion in ERCOT, the MISO, and the NYISO have been to increase the deliverability of renewable generation to consumers.
- ISO-NE generally incurs more market-wide uplift costs, adjusted for its size, than MISO and NYISO. The higher costs arise partly because ISO-NE's fuel costs tend to be higher and partly because it does not have day-ahead ancillary services markets to offset the cost of committing generation to satisfy operating reserve requirements.
- The virtual trading levels in ISO-NE have been substantially lower than the levels observed in NYISO and MISO. This is because ISO-NE over-allocates real-time NCPC charges to virtual transactions and other real-time deviations. (See Recommendation #1) Virtual trading will play an important role in aligning prices in the newly proposed day-ahead energy and ancillary services markets with the prices in the real-time market.
- The CTS process between New England and New York has improved over time because of: a) improvements in price forecasts; and b) increased CTS bid liquidity that has benefitted from the RTOs' decision not to impose charges on these transactions. These two factors have led to substantial production cost savings. It is by far the best performing CTS that has been implemented to date (CTS process have been implemented between PJM and both NYISO and MISO). However, forecast errors limit the potential benefits of CTS, so the ISO should continue to pursue forecasting improvements. (See Recommendation #5)

Competitive Assessment

Based on our evaluation of the ISO-NE's wholesale electricity markets contained in Section II of this report, we find that the markets performed competitively in 2019. Our pivotal supplier analysis suggests that structural market power concerns diminished noticeably in Boston and New England over the past two years because of the entry of more than 2.5 GW of generation over the past two years, transmission upgrades in Boston, and falling load levels. Our analyses of potential economic and physical withholding also indicates that the markets performed competitively with little evidence of significant market power abuses or manipulation in 2019.

In addition, we find that the market power mitigation has generally been effective in preventing the exercise of market power in the New England markets, and was generally implemented consistent with Appendix A of Market Rule 1. The automated mitigation process helps ensure the competitiveness of market outcomes by mitigating attempts to exercise market power in the real-time market software before it can affect the market outcomes.

To ensure competitive offers are not mitigated, it is important for generators to proactively request reference level adjustments when they experience input cost changes due to fuel price volatility and/or fuel quantity limitations. In addition, the ISO implemented a procedure before the 2018/19 winter to allow opportunity costs resulting from fuel limitations in reference levels for oil-fired and dual-fuel generators. Although its effectiveness has not yet been truly tested because of relatively mild winter conditions, this enhancement should lead to more efficient scheduling of energy-limited resources. We will continue monitor its effectiveness particularly under prolonged severe winter weather conditions.

The only area where the mitigation measures may not have been fully effective is in their application to resources frequently committed for local reliability. Although the mitigation thresholds are tight, the suppliers have the incentive to operate in a higher-cost mode and receive higher NCPC payments as a result. Hence, we recommend the ISO consider tariff changes as needed to expand its authority to address this concern. (See Recommendation #2)

Reliability Commitment and NCPC Uplift

The ISO commits resources within the day-ahead market scheduling process to satisfy two types of reliability requirement that are not reflected in the market clearing prices:

- The ISO commits local second contingency protection resources to ensure the ISO is able to reposition the system in key areas in response to the second largest contingency after the first largest contingency has occurred.
- The ISO also commits sufficient resources to satisfy system-level operating reserve requirements in the day-ahead market.

These local and system-level reserve requirements are not enforced in the day-ahead market pricing software. Consequently, generators are frequently committed in the day-ahead market to satisfy local and systemwide reserve requirements, but the clearing prices of energy (and reserves) are understated because they do not reflect the costs of satisfying these reserve requirements.

In addition, since the day-ahead market schedules resources to satisfy load bids rather than forecast load, the ISO sometimes needs to commit additional generators with high commitment costs after the day-ahead market to satisfy forecast load and reserve requirements. Such commitments generate expenses that are uplifted to the market and increase the amount of supply available in real time, which depresses real-time market prices and leads to additional uplift, undermining market incentives for meeting reliability requirements. In Section III of this report, we evaluate supplemental commitment by the ISO to maintain reliability, the resulting NCPC charges, and impacts on market incentives. In its Energy Security Initiative, the ISO has recently taken a major step towards addressing these market inefficiencies by proposing to incorporate system-level reserve requirements into its day-ahead market.

In our assessment of day-ahead reliability commitments, we found that in 2019:

- Commitment for local second contingency protection occurred in roughly 1,800 hours, leading to nearly $7 million (or 54 percent) of day-ahead NCPC.
- Additional commitment to satisfy the system-level 10-minute spinning reserve requirement occurred in roughly 3,800 hours, leading to more than $4 million (or 33 percent) of day-ahead NCPC.

Both of these requirements are satisfied by scheduling operating reserves, but operating reserves are not procured in the day-ahead market and the cost of scheduling operating reserves is not reflected efficiently in energy prices. As a result, resources that provide these services are often undervalued. The resulting NCPC uplift per MWh of committed capacity ranged from:

- Roughly $8 to $22 per MWh in local regions for second contingency commitment; and
- Around $2 to $3 per MWh for system-level 10-minute spinning reserve commitment.

The average uplift charges provide some indication of how clearing prices may be understated for certain products. In addition, we continue to find that these price effects are inflated when the ISO is compelled to start combined-cycle resources in a multi-turbine configuration when its reliability needs could have been satisfied by starting them in a single-turbine configuration. In 2019, multi-turbine combined-cycle commitments accounted for more than 40 percent of the capacity committed for local reliability in the day-ahead market.

ISO-NE recently proposed to incorporate three new reserve products into the day-ahead market, which will be co-optimized with energy procurement. Most NEPOOL members have opposed the scheduling of replacement reserves outside the winter months. Our assessment finds that:

- Available resources capable of providing 30-minute reserves, while usually adequate to satisfy the 30-minute reserve requirement, was not sufficient to satisfy the forecasted energy and 4-hour replacement reserve requirement on almost every day of 2019.
- Available resources offering to respond within four hours was adequate to satisfy the 4-hour replacement reserve requirement on 94 percent of days in 2019. However, the margin was generally slim, so changes in the resource mix and/or scheduling patterns could lead to significant supplemental commitment in the future if the ISO does not procure reserves in the day-ahead market to satisfy its replacement reserve needs.
- The need to procure these ancillary services in the day-ahead market for the forecasted energy and reserve requirement exists not just in the winter season, but also during other months.

Therefore, we support this effort by the ISO and make three recommendations to improve the pricing of energy and operating reserves. We recommend that the ISO:

- Expand its authority to commit combined-cycle units in a single-turbine configuration when that will satisfy its reliability need. (See Recommendation #2)
- Co-optimize the scheduling and pricing of operating reserves in the day-ahead and real-time markets for a comprehensive set of local reserve requirements to satisfy its local second contingency protection requirements. (See Recommendation #3)
- Eliminate of the Forward Reserve Market, which has resulted in inefficient economic signals and market costs. Implementation of day-ahead reserve markets further decreases any potential value this market may have offered. (See Recommendation #4)

We strongly support the ISO's recently announced proposal to eliminate the Forward Reserve Market, which has several major deficiencies. First, a forward reserve provider is required to offer at the cost of a relatively inefficient peaking generator, which leads most forward reserve providers to offer energy at inflated price levels, leading to inefficient dispatch and distorted clearing prices for both energy and real-time operating reserves. Second, the settlement rules for forward reserve providers do not provide efficient incentives for them to be available in the real-time market, so the forward reserve market design must resort to penalty provisions to motivate suppliers. Third, forward reserve providers must satisfy their obligations 16 hours per day without coordinated scheduling through the centralized day-ahead market. This raises the cost of participation by non-peaking generators, thereby placing an unnecessary barrier to participation in the reserve market. Fourth, the forward reserve market only satisfies a subset of the ISO's overall reserve requirements, so it does little to reduce the need for the ISO to commitment out-of-market to satisfy its reliability requirements.

Investment Incentives and Policy-Driven Investment

The New England states have ambitious clean energy targets which will require large amounts of new intermittent renewable generation, flexible resources, and price-responsive demand to balance variations in intermittent renewable generation. Some have begun to question the value of competitive wholesale markets if so much investment will result from state policy initiatives. However, given the high levels of generation investment that are anticipated to occur in the coming years, it has become more important than ever to provide efficient investment incentives to developers of intermittent generation and battery storage. Wholesale markets are highly effective in guiding investment towards projects that provide value to a system, and state policy makers should leverage the power of markets to achieve their clean energy objectives more quickly and cost-effectively. Section IV discusses how the competitive wholesale market complements these public policy initiatives and the implications for the New England generation fleet.

Our analysis of investment in several new renewable and flexible resources indicates that there are significant differences in the IRR ("Internal Rate of Return") by technology and location. Of the renewable technologies we analyzed, onshore wind appears more profitable than utility-scale solar and offshore wind generation, so utility-scale solar and offshore wind projects will require larger subsidies per MWh to motivate investment. For the flexible technologies studied, investment in battery storage resources is expected to produce higher returns than investment in CTs based on forward prices, which is consistent with their ability to balance a system with high levels of intermittent output. Overall, we find that markets will complement states' policies by setting prices that:

(a) reward flexible technologies as the penetration of renewables increases,

(b) encourage renewable resources to locate where their output will be deliverable to consumers, and

(c) channel investment toward renewable generation projects that produce electricity when it is more valuable.

Several forthcoming market design initiatives are likely to enhance the alignment of the prices with the value of generation, and can further facilitate an efficient transition to a low carbon grid, particulary in conjunction with additional carbon pricing.

New England is well-positioned to balance state policy and market competitiveness concerns with a FERC-approved CASPR mechanism already in place. Furthermore, the CASPR mechanism is superior to long-term contracts that some have promoted as a means to satisfy resource adequacy needs. Moving away from centralized capacity markets to a long-term contracts model would be extremely costly and inefficient. A long-term contracting model will not coordinate efficient investment in new resources and retirement of existing resources, making it extremely difficult for the states to achieve their ambitious environmental policy goals at a reasonable cost. Furthermore, the long-term state-directed contracting model would: not procure resources in the most valuable technologies and/or locations, place excessive investment risk on end users and be detrimental to innovation overall.

Our analysis indicates that of the existing technologies we evaluated, steam turbine units are the most challenged economically largely because of lower capacity prices in the upcoming Capacity Commitment Periods and higher risk of PFP-related penalties. Hence, some steam turbine units may contemplate retirement. However, there is considerable uncertainty regarding the actual price level at which an existing unit owner would choose to retire because of a number of factors. In particular, the imminent retirement of Mystic 8 and 9 units (1.4 GW) may have led asset owners to risk negative cash flows for one or two years in anticipation of higher capacity prices in FCA-15. However, the potential upside to capacity prices from the retirement of Mystic 8 and 9 units is limited by: (a) potential repowering that would replace the capacity retiring at the existing Mystic site, and (b) the potential entry of unsubsidized battery storage resources. By the middle of this decade, we expect the falling entry costs of battery storage projects to increase pressure on some steam turbines to retire.

Overall, our analysis suggests that there is likely to be a significant potential demand to meet the supply of state-policy resources in future auctions. However, the timing of retirements may be difficult to determine as owners have considerable latitude in deferring costs. Further, to the extent units with a high degree of availability or flexibility enter the market, the financial pressure on steam turbines could be alleviated by a reduction in the frequency of shortages. This is a key factor because the frequency of PFP events substantially affects the economics of the steam turbines.

Incentives of Pay-for-Performance Rules

The Pay-for-Performance ("PFP") rules were implemented to enhance incentives for suppliers to perform when they are needed the most. This report summarizes market outcomes during the first PFP event since the rules became effective on June 1, 2018. In Section V, we evaluate the efficiency of compensation received by suppliers during the event compared to the risk of not serving load and the value of lost load. We also identify a misalignment between the compensation of short-duration energy limited resources and their value to the system during reserve shortage events.

In the only PFP event that has occurred since the PFP framework was implemented, the ISO ran short of 10-minute and 30-minute reserves. The shortage resulted primarily from unexpectedly high load (actual load exceeded the forecast by roughly 2.5 GW) and the sudden loss of generation (roughly 1.4 GW). The combination of shortage pricing and PFP incentives led to marginal compensation rates of up to $4700 per MWh. Performance of individual resources was generally consistent with expectations as steam turbines accounted for the majority of PFP charges, since most had not been economic to commit in the day-ahead market, while other resource categories generally received more credits than charges with fast-start units and importers doing particularly well.

PPR versus the Marginal Value of Reserves

During reserve shortages, prices should rise gradually with the severity of the shortage, reflecting the marginal reliability value of reserves given the size of the shortage and the risk of potential supply contingencies. The marginal reliability value of reserves is the expected value of lost load ("EVOLL") that will not be served if the available reserves are reduced by 1 MW. Assuming a relatively high value of lost load ("VOLL") of $30,000 per MWh, we estimated the EVOLL based on the probability of contingencies that could result in load shedding during the first-ever PFP event. The EVOLL is important because it reflects efficient shortage compensation for resources that are producing energy and/or reserves.

We estimate that the EVOLL ranged from $700 to $1000 per MWh during the event, far lower than the marginal rate of compensation under the PPR, which ranged from $3000 to $4700 per MWh. However, we find that for 10-minute reserve shortages of more than 540 MW, the EVOLL would quickly rise above $4700 per MWh up to the assumed VOLL of $30,000 per MWh. This illustrates the deficiencies with the current PPR, that the single payment rate is: a) well above a reasonable estimate of the average EVOLL, and b) fixed regardless of the magnitude of the shortage. Hence, we recommend the ISO modify the PPR to rise with the reserve shortage level, and not to implement the remaining planned increase in the payment rate. (See Recommendation #7) These changes would enhance price formation during reserve shortage events and encourage more efficient short and long-run decisions by suppliers.

Incentives for Energy Storage Resources and Large Generators

Interest in battery storage and other energy limited resources has grown quickly in recent years as policy-makers look for non-fossil fuel options for integrating intermittent renewables. However, these resources present special challenges for valuing capacity and energy and operating reserves under shortage conditions. We evaluate the reliability value of a 2-hour battery storage resource and find that such units are likely to be over-compensated under the current capacity market rules, including the PFP compensation provisions. This is concerning as policy-makers and developers prepare to invest heavily in this technology in the coming years.

The FCM rules allow battery storage resources to qualify for 100 percent of their maximum capability, but these resources have significant duration limitations that make them less valuable than most conventional resources when the system is near load shedding conditions. Furthermore, the flexibility of these resources make them likely to perform better under the PFP provisions than most resources during mild to moderate reserve shortage conditions. As discussed above, the marginal compensation rate is far higher than the EVOLL during such reserve shortages, leading battery storage resources to be greatly over-compensated.

We performed a Monte Carlo analysis to estimate the reliability value of a 2-hour battery storage resource for avoiding load shedding and the compensation it would receive in the capacity market. This found that a 2-hour battery storage resource would:

- Have 66 percent of the value of an average conventional resource for avoiding load shedding, and
- Receive 117 percent of the total capacity compensation of an average conventional resource.

This over-compensation cannot be resolved by reducing the qualified capacity of these resources to an appropriate level (e.g., 66 percent), since this reduction would be offset by a significant increase in the PFP credit.

In addition, a single PPR value for all reserve shortages may provide excessive disincentives for large resources to continue operating, since the forced outage of a large resource is more likely to cause a shortage event than the forced outage of a small generator. Therefore, to the extent that the current framework utilizes a higher PPR (relative to the efficient level as determined by the EVOLL curve) during shortage events, larger units are likely to be over-penalized. In addition, since a majority of the reserve shortage events are likely to be shallow, a flat and high PPR could result in significant disincentives for larger units.

As stated earlier, a graduated PPR that rises with the magnitude of the reserve shortage would largely correct the issues related to over-/under compensation to battery storage and large resources.. Hence, we recommend that the ISO: (a) reduce the qualified capacity of 2-hour battery storage resources before the FCA, and (b) adopt a graduated PPR that rises with the magnitude of the reserve shortage. (See Recommendations #7 and #8)

Capacity Market Design Enhancements

The purpose of the capacity market is to provide a market mechanism for ensuring that sufficient resources are procured to satisfy the planning reliability requirements of New England. The forward capacity market coordinates decisions to retire or mothball older resources with decisions to invest in new generation, demand response, and transmission. We evaluate potential market design improvements to facilitate competition in the auction and to enhance incentives for timely delivery of new resources.

Addressing Issues in the Minimum Offer Price Rules

The purpose of the minimum offer price rule ("MOPR") is to prevent uneconomic subsidized resources from artificially depressing market prices. This is important because these price effects will undermine the market's ability to facilitate efficient long-term investment and retirement decisions by market participants. However, MOPR can also potentially interfere with competitive investment or artificially increase prices. Hence, it is important to ensure that MOPR is effective in addressing uneconomic entry while not interfering with economic entry. Based on our evaluation of the MOPR in previous years, we've identified three issues that we recommend the ISO address to improve its MOPR.

Conforming the MOPR to the Pay-for-Performance Framework

Under the PFP rules, most of the value of capacity in the long-run will be embedded in the performance payments. Participants that sell capacity are essentially engaging in a forward sale of the expected performance payments (they receive the capacity payment up front in exchange for not receiving the performance later when they are running during a shortage). However, resources that do not sell capacity can earn comparable revenues by simply running during shortages and receiving the performance payments. In other words, a supplier has two options:

- Sell capacity and commit to producing energy during shortages, relinquishing the performance payments in could have earned; or
- Do not sell capacity and earn the performance payments by producing during shortages.

In equilibrium, these two options should produce the same expected revenues. MOPR precludes an uneconomic entrant from selling capacity (choosing the first option), which simply means that the mitigated resource would default to option 2. Because option 2 should provide substantial expected revenues, the MOPR may not be an effective deterrent under the PFP framework. In addition, an uneconomic entrant will be able to depress capacity prices without selling capacity because it will lower the expected number of shortage hours. Therefore, we recommend the ISO make units that were mitigated under the MOPR ineligible to receive performance payments. (See Recommendation #9a)

Competitive Entry Exemption

As noted above, the MOPR is intended to address uneconomic subsidized new resources that can artificially increase supply and depress prices. However, the current rules apply to all investment in new resources, including private investment in resources that are receiving no out-of-market subsidies. To the extent that the MOPR affects the offer prices submitted for such resources, it will interfere with competitive market-based investment.

Other RTOs have addressed this concern by implementing a "competitive entry exemption" to prevent the MOPR from interfering with private market-based investment.[3] Essentially, such a provision would exempt a new resource from the MOPR if it demonstrates that it is not receiving any direct subsidies or indirect subsidies via contract with a regulated entity. (See Recommendation #9c)

3 See NYISO's Market Administration and Control Area Services Tariff section 23.4.5.7.9.

Capping the Minimum Offer Price

The MOPR is intended to prevent prices from reflecting artificial supply surpluses caused by uneconomic entry. There is no economic justification, however, for mitigating new resources when surplus capacity is zero or negative (i.e., new resources are needed to satisfy the system's planning needs). In this case, a competitive and efficient market would facilitate entry at price close to the net CONE, and no price above this level can reasonably be considered depressed. Likewise, it is unreasonable for the MOPR raising prices substantially above net CONE. Unfortunately, this outcome would occur under ISO-NE's current MOPR.

ISO-NE's version of the MOPR always sets the offer floor at the new resource's actual entry cost, even though it may be much higher than net CONE (currently near $8 per kw-month). This may prevent state-sponsored resources that could satisfy a capacity need from clearing in the FCA and prompt the ISO to clear a conventional resource that is not needed (given the entry of the sponsored resource). This raises additional concerns under the ISO's recently approved Competitive Auctions with Subsidized Policy Resources ("CASPR") provisions because clearing unneeded conventional resources will compel the sponsored resources to pay lower-cost existing resources to retire.

Addressing this issue is straightforward. We recommend that ISO-NE cap the minimum offer price at net CONE. This will prevent artificial suppression of capacity prices below net CONE, but would ameliorate the concerns described above. It would allow sponsored resources to enter at an offer equal to net CONE and displace new conventional resources offered at higher prices. (See Recommendation #9b) To the extent that some sponsored resources clear in the FCA at or above net CONE, fewer lower-cost existing resources would be prompted to retire and fewer unneeded conventional new resources would enter, both of which would increase efficiency and lower costs for the regions' consumers.

Improving the Competitive Performance of the FCA

In our previous Annual Market Reports, we evaluated the supply and demand in the FCA and concluded that:[4]

- Limited competition can enable a single supplier to unilaterally raise the capacity clearing price by a substantial amount.
- Publishing information on qualified capacity and the Descending Clock Auction format help suppliers recognize when they can benefit by raising capacity prices.

4 See Section V.A of our report on *2014 Assessment of the ISO New England Electricity Markets*, Section IV.A of *2015 Assessment of the ISO New England Electricity Markets*, and Section IV.A of *2017 Assessment of the ISO New England Electricity Markets*.

Most of the pre-auction information available to auction participants regarding the existing, new and retiring resources either needs to be published for other purposes or is available from sources that are outside the ISO's purview. However, the ISO's DCA process provides key information on other suppliers offers that is not relevant for constructing competitive offers, and instead would allow a resource to raise its offer above competitive levels. A sealed bid auction would eliminate such information and improve the incentives for suppliers to submit competitive offers. Accordingly, we recommend the ISO transition from the DCA to a sealed-bid auction. (See Recommendation #6)

Table of Recommendations

Although we find that the ISO-NE markets have generally performed competitively and efficiently, we identify a number of opportunities for improvement. Therefore, we make the following recommendations based on our assessments discussed in this report.. A number of these recommendations have been made previously and are now reflected in the ISO's Wholesale Market Plan.

Recommendation	High Benefit[5]	Feasible in ST[6]
Reliability Commitments and NCPC Allocation		
1. Modify allocation of "Economic" NCPC charges to make it consistent with a "cost causation" principle.		✓
2. Utilize the lowest-cost fuel and/or configuration for multi-unit generators when committed for local reliability.		✓
Reserve Markets		
3. Incorporate a comprehensive set of local operating reserve requirements into the day-ahead and real-time markets.		
4. Eliminate the forward reserve market.		✓
External Transactions		
5. Pursue improvements to the price forecasting that is the basis for Coordinated Transaction Scheduling with NYISO.	✓	✓

5 Recommendation will likely produce considerable efficiency benefits.

6 Complexity and required software modifications are likely limited.

Capacity Market	
6. Replace the descending clock auction with a sealed-bid auction to improve competition in the FCA.	✓
7. Modify the PPR to rise with the reserve shortage level, and not implement the remaining planned increase in the payment rate.	
8. Consider modifying the capacity compensation of energy limited resources to be consistent with its reliability value.	
9. Improve the MOPR by: a) eliminating performance payment eligibility for units subject to the MOPR, b) capping the Minimum Offer Price at net CONE, and c) exempting competitive private investment from the MOPR.	✓

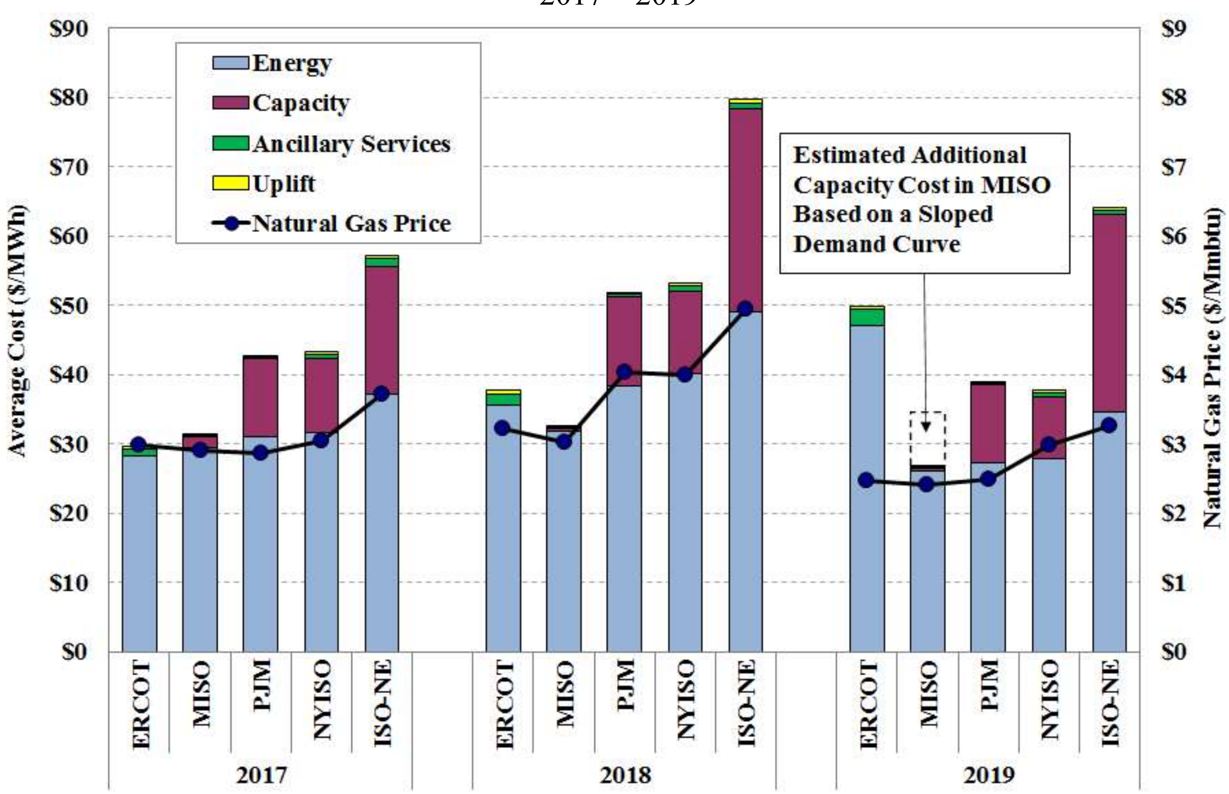
I. Comparing Key ISO-NE Market Metrics to Other RTOs

The 2019 Annual Markets Report by the Internal Market Monitor (IMM) provides a wide array of descriptive statistics and useful summaries of the market outcomes in the ISO-NE markets. The IMM report provides a very good discussion of these market outcomes and the factors that led to changes in the outcomes in 2019. Rather than duplicating this discussion, we attempt to place the key market outcomes into perspective in this section by comparing them to comparable outcomes and metrics in other RTO markets.

A. Market Prices and Costs

While the RTOs in the US have migrated to using similar market designs, including Locational Marginal Pricing (LMP) energy markets, operating reserves and regulation markets, and capacity markets, the details of the market rules can vary substantially. In addition, the market prices and costs in different RTOs can be significantly affected by the types and vintages of the generation, the input fuel markets and availability, and differences in the capability of the transmission network. To compare the overall prices and costs between RTOs, we produce the "all-in price" of electricity in Figure 1.

Figure 1: All-In Prices in RTO Markets
2017 – 2019



The all-in price metric is a measure of the total cost of serving load. The all-in price is equal to the load-weighted average real-time energy price plus capacity, ancillary services, and real-time uplift costs per MWh of real-time load. We also show the average natural gas price because it is a principal driver of generators' marginal costs and energy prices in most markets.

This figure shows some clear sustained differences in prices and costs between these markets. ISO-NE has exhibited the highest energy prices of these markets with the exception of ERCOT, which is discussed below. The relatively high energy costs in New England are primarily attributable to the higher natural gas prices at the pipeline delivery locations serving New England's generators. However, the natural gas price premium is larger than the energy price premium in New England because average system-wide energy prices in all other markets are increased by transmission congestion.

Although we do not show the most congested locations in neighboring markets, such as New York City, these import-constrained locations exhibit all-in prices substantially higher than prices in New England and contribute to higher system-wide average prices in those markets. Conversely, the unusually low levels of transmission congestion in New England tends to lead to lower system-wide average energy prices. We discuss congestion levels and trends in more detail in the next subsection.

The figure also shows that the capacity costs in New England were substantially higher than the other RTO's shown. The capacity costs for NYISO were lower primarily because the capacity surplus in its "prompt market" design was larger than the surplus in New England's "forward market" design over these three years. A substantial surplus has also prevailed in PJM. Load forecasts have played a key role in the differences in the outcomes between these two markets:

- Both markets have experienced significant declines in their load forecasts in recent years because of energy efficient, behind-the-meter solar installations, and changing consumption patterns;
- ISO-NE's load forecast for the summer of 2019 fell from 27.3 GW in the forecast performed in 2015 that was used to develop inputs for FCA 10 to 25.3 GW in the 2019 CELT Report, a reduction of 7 percent. The NYISO's load forecast for the summer of 2019 fell by 5 percent over the same period.[7]
- Hence, both markets have made large downward revisions in their load forecasts for this period, however, such revisions are recognized immediately in the NYISO's prompt capacity market design, while they are recognized on a four-year delay in New England's forward market. This load forecast change has been a key contributor to the 72 percent decline in the capacity compensation rate from the 2019/20 Capability Year to the 2023/24 Capability Year.

7 See NYCA Summer Peak Demand Baseline forecast in the 2015 and 2019 *Load & Capacity Data "Gold Book"* reports.

The low capacity costs in the ERCOT and MISO markets were attributable to their market designs. ERCOT operates an "energy-only" market (i.e., no capacity market) with a $9000 shortage price. Energy prices in ERCOT hit $9000 per MWh in several hours in the Summer 2019 because of hot temperatures and planning reserve margins less than 9 percent. This contributed to a substantial increase in its annual average energy costs. This sharp increase in energy costs (with no significant change in natural gas prices) illustrates the potential for price volatility in an energy-only market with strong shortage pricing rules. However, ERCOT market participants reduce much of their exposure to this volatility by entering into forward hedging contracts. ERCOT relies primarily on shortage pricing to provide long-term incentives to facilitate investment and retirement decisions. This is only feasible in ERCOT because it does not enforce planning reserve requirements, unlike the other ISOs shown in this figure.

MISO operates a capacity auction with a vertical demand curve that is not designed to reveal the true value of capacity. As a result, capacity prices are understated (as shown by the skeleton bar in the figure) and do not provide efficient long-term incentives. Although not optimal, MISO has been content with this market design because additional revenues are provided through retail rates to regulated entities that play a key role in maintaining resource adequacy in MISO. The figure above shows that if MISO were to adopt an efficient sloped demand curve, the all-in prices would increase to a level that is closer to the levels in New England. It would still be lower as energy prices are lower in the Midwest.

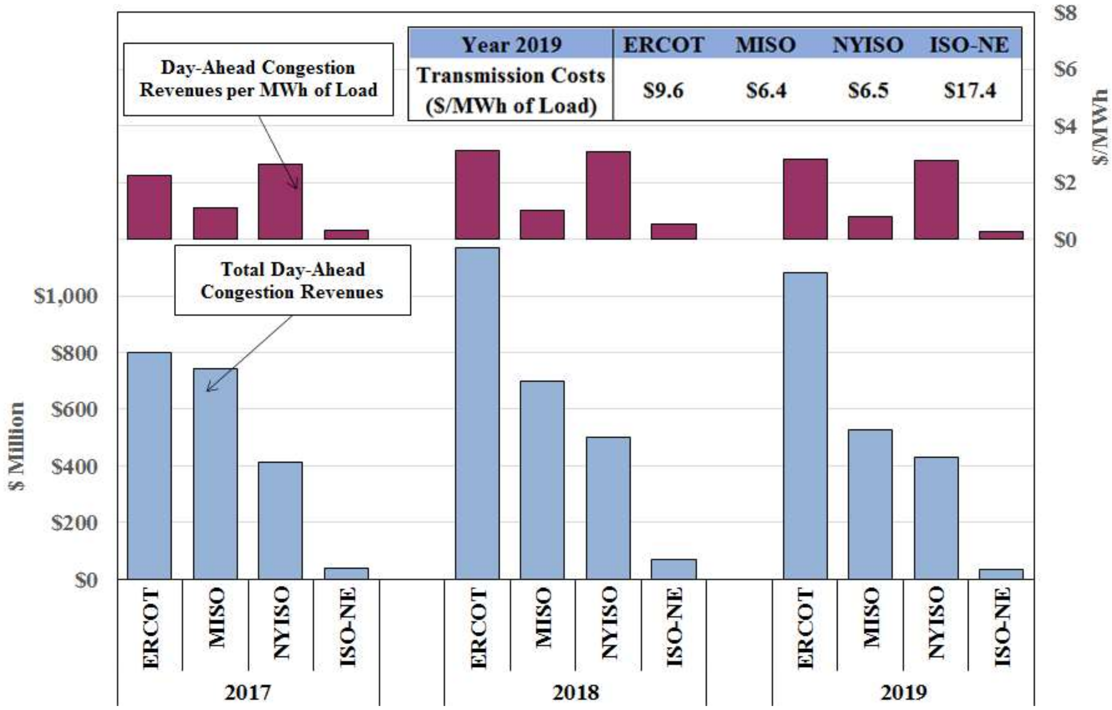
The other result shown in the figure, although it is difficult to discern, is that the average uplift costs per MWh of load was higher in ISO-NE than the other markets shown in most years. Although this amount is small, it is important because it is difficult to hedge. In addition, it tends to occur when the market requirements are not fully aligned with the system's reliability needs or prices are otherwise not fully efficient. We discuss uplift in more detail in Subsection C.

B. Transmission Congestion

One of the principal objectives of the day-ahead and real-time markets is to commit and dispatch resources to control flows on the transmission system and efficiently manage transmission congestion. Figure 2 shows the amount of congestion revenue collected through the day-ahead markets in a number of RTO markets in the U.S. To account for the very different sizes of these RTOs, we show the total amount of day-ahead congestion revenues divided by actual load in the top panel of the figure.

Figure 2 shows that ISO-NE experiences far less congestion than any of these other RTOs. On a per MWh basis, congestion levels in the other RTOs are five to ten times larger than the congestion levels in New England. The low level of congestion in New England is not a surprise given the substantial transmission investments that were made over the past decade. These investments have led transmission rates to be over $17 per MWh, which are more than double the average rates in the other RTO areas shown in the figure.

Figure 2: Day-Ahead Transmission Revenues



The transmission rates in other RTO areas are much lower than New England, even given the billions in incremental transmission costs that have been incurred in Texas and MISO to support the integration of wind resources. For example, ERCOT has incurred more than $5 billion in transmission expansion costs to mitigate the transmission congestion between the wind resources in west Texas and the load centers in eastern Texas, while MISO began investing in transmission projects that are anticipated to exceed $15 billion to integrate renewable resources throughout MISO. Although the NYISO did not expand transmission significantly from 2017 to 2019, the NYISO has approved nearly $2 billion in transmission projects principally focused on delivering renewable energy from upstate New York to load centers in New York City and Long Island.

Hence, the primary reasons for transmission expansion in ERCOT, MISO, and NYISO have been to increase the deliverability of renewable resources to consumers. In contrast, the transmission investments in ISO-NE have generally been made for different reasons:

- In northern New England, transmission upgrades have been focused on improving the performance of the long 345 kV corridors, particularly through Maine.
- In southern New England, investments have been made to satisfy ISO New England's planning requirements to ensure the ISO can maintain reliability in the face of generation retirements throughout this area.

ISO New England's reliability planning process identifies a local need for transmission whenever the largest two contingencies would result in the loss of load under a 90th-percentile peak load scenario. This criteria is much more stringent than the reliability planning criteria used in the other three markets. The estimated investment in New England to maintain reliability has been $10.9 billion from 2002 to June 2019, and another $1.3 billion is planned over the next planning horizon. In general, transmission investment is more economic than generation and/or demand response when the marginal benefit of reducing congestion is greater than the marginal cost of the transmission investment. Given that average congestion in New England has been less than $0.40 per MWh over the past three years, it is unlikely that additional transmission investment would be economic in the near term.

C. Uplift Charges and Cost Allocation

Although NCPC costs (generally referred to as "Make-Whole Uplift Charges" industry-wide) generally account for a small share of the overall wholesale market costs, they are important because they usually occur when the market requirements are not fully aligned with the system's reliability needs or prices are otherwise not fully efficient. The cost of satisfying some needs will be reflected in NCPC payments rather than in market-clearing prices. Ultimately, this undermines the economic signals that govern behavior in the day-ahead and real-time markets in the short-term and investment and retirement decisions in the long-term. Thus, we evaluate the causes of NCPC payments to identify potential inefficiencies.

Table 1 summarizes the total day-ahead and real-time NCPC charges in ISO-NE over the past three years, and it shows the comparable 2019 uplift charges for both NYISO and MISO. Because the size of the ISOs varies substantially, the table also shows these costs per MWh of load. Recognizing that some RTOs differ in the extent to which they make reliability commitments in the day-ahead horizon versus real-time, the table includes a sum of all day-ahead and real-time uplift at the bottom to facilitate cross-market comparisons.

Table 1: Summary of Uplift by RTO

		ISO-NE			NYISO	MISO
		2017	2018	2019	2019	2019
Real-Time Uplift						
Total	Local Reliability ($M)	$1	$4	$2	$15	$4
	Market-Wide ($M)	$23	$40	$16	$9	$72
Per MWh of Load	Local Reliability ($/MWh)	$0.01	$0.04	$0.01	$0.09	$0.01
	Market-Wide ($/MWh)	$0.19	$0.32	$0.14	$0.06	$0.11
Day-Ahead Uplift						
Total	Local Reliability ($M)	$15	$14	$7	$24	$21
	Market-Wide ($M)	$13	$12	$6	$4	$14
Per MWh of Load	Local Reliability ($/MWh)	$0.12	$0.11	$0.06	$0.16	$0.03
	Market-Wide ($/MWh)	$0.11	$0.10	$0.05	$0.02	$0.02
Total Uplift						
Total	Local Reliability ($M)	$16	$18	$9	$39	$25
	Market-Wide ($M)	$36	$52	$22	$13	$86
Per MWh of Load	Local Reliability ($/MWh)	**$0.13**	**$0.15**	**$0.07**	**$0.25**	**$0.04**
	Market-Wide ($/MWh)	**$0.29**	**$0.42**	**$0.19**	**$0.08**	**$0.13**
	All Uplift ($/MWh)	**$0.42**	**$0.57**	**$0.26**	**$0.33**	**$0.17**

Market-Wide Uplift. Table 1 shows that ISO-NE incurred more market-wide uplift costs in 2019, adjusted for its size, than the other two markets. The higher market-wide costs arise partly because ISO-NE's fuel costs tend to be higher than the other RTO's, which generally leads to higher required make-whole payments. In addition, MISO and NYISO have day-ahead ancillary services markets, which reduce the uplift charges for generation that is committed primarily to maintain adequate operating reserves at the local and/or system levels. ISO-NE's recently filed day-ahead ancillary services market design should significantly reduce such uplift charges once it is implemented. We discuss the other drivers of these uplifts in Section III in this report.

Local Reliability Uplift. Table 1 also shows that local reliability NCPC uplift fell notably in 2019 from prior years. This was driven primarily by reduced supplemental commitments in the Boston area because of:

- The transmission upgrades (i.e., the Greater Boston Reliability Project), which increased the import capability into the Boston load pocket by more than 400 MW when they were completed in mid-2019; and
- The entry of the 700 MW Footprint combined-cycle plant in mid-2018.

These additions have greatly reduced the ISO's reliance on the Mystic generating units that were previously committed frequently to maintain reliability in the Boston area.

Uplift for local reliability was smaller in ISO-NE than in the NYISO market, where relatively large amounts of generation must be committed for local second contingency protection in New York City. Since these local reliability requirements are not adequately reflected in the NYISO operating reserve market, it results in large uplift charges and poor investment incentives. On the other hand, local reliability uplift in ISO-NE was higher than in the MISO market where few areas require commitment for local second contingency protection. However, the difference between the two markets declined significantly in 2019.

In addition to the differences in the magnitude of the uplift costs, the allocation of the uplift costs also varies substantially among the RTOs. ISO-NE allocated approximately half real-time NCPC charges to real-time deviations, including virtual transactions. However, most of the NCPC charges that are allocated to real-time deviations are not caused by real-time deviations. This misallocation of NCPC charges distorts market incentives to engage in scheduling that can lead to real-time deviations. Unfortunately, this distortion is compounded by the fact that NCPC charges are allocated to real-time deviations that actually help reduce NCPC charges such as virtual load and over-scheduling of load in the day-ahead market.

Over-allocating NCPC charges to real-time deviations has resulted in higher costs for virtual transactions in New England than in other RTO markets, which tends to reduce their participation in the market and the overall market liquidity. This is undesirable because in organized wholesale power markets, virtual trading plays a key role in the day-ahead market by providing liquidity and improving price convergence between day-ahead and real-time markets.

Table 2 shows the average volume of virtual supply and demand that cleared the three eastern RTOs we monitor as a percent of total load, as well as the gross profitability of virtual purchases and sales. Gross profitability is the difference between the day-ahead and real-time energy prices used to settle the energy that was bought or sold by the virtual trader. The profitability does not account for uplift costs allocated to virtual transactions, which are shown separately.

Table 2: Scheduled Virtual Transaction Volumes and Profitability

Market	Year	Virtual Load		Virtual Supply		Uplift Charge Rate
		MW as a % of Load	Avg Profit	MW as a % of Load	Avg Profit	
ISO-NE	2016	1.3%	$1.70	2.0%	$1.94	$1.25
	2017	2.2%	$1.98	3.6%	$2.71	$0.81
	2018	2.7%	$1.10	4.5%	$2.69	$0.94
	2019	2.3%	-$1.20	4.9%	$1.26	$0.40
NYISO	2019	6.7%	$0.17	14.5%	$0.43	< $0.1
MISO	2019	10.8%	-$0.07	11.3%	$0.94	$0.37

Table 2 shows that virtual trading was generally profitable, indicating that it has generally improved price convergence between the day-ahead and real-time markets. The average volume of cleared virtual transactions increased slightly in recent years as uplift charges to real-time deviations have declined. In spite of the increased volumes, the virtual trading levels were still substantially lower than the levels observed in both the NYISO and MISO markets. In 2019, the gross volume of cleared virtuals (including both virtual load and virtual supply) averaged roughly 7 percent of load in the ISO-NE market, compared to 21 and 22 percent in the NYISO and MISO markets, respectively. We believe this substantial difference is primarily due to the costs that are allocated to virtual transactions in New England.

ISO-NE's NCPC allocation methodology, which raises significant concerns. In spite of the decrease in recent years, the NCPC charges remain higher and more uncertain than the charges imposed by the other RTOs. Additionally, it results in large NCPC cost allocations to virtual load even though virtual load generally *reduces* NCPC costs. This provides a substantial disincentive for firms to engage in virtual trading, ultimately reducing liquidity in the day-ahead market. This explains why the gross profitability of virtual transactions is much larger in ISO-NE than the other RTOs (i.e., the day-ahead and real-time prices are not as well arbitraged).

Hence, we continue to recommend the ISO modify the allocation of Economic NCPC charges to be more consistent with a "cost causation" principle, which would involve not allocating NCPC costs to virtual load and other real-time deviations that cannot reasonably be argued to cause real-time economic NCPC. This will ultimately be necessary when the ISO implements day-ahead ancillary services markets.

D. Coordinated Transaction Scheduling

Coordinated Transaction Scheduling ("CTS") is a market process whereby two neighboring RTOs exchange real-time market information to schedule external transactions more efficiently. CTS is very important because it allows the large interface between markets to be more fully utilized, which lowers costs and improves reliability in both areas. The benefits of CTS are likely to grow in the future as the addition of intermittent generation makes it more difficult for RTOs to balance supply and demand.

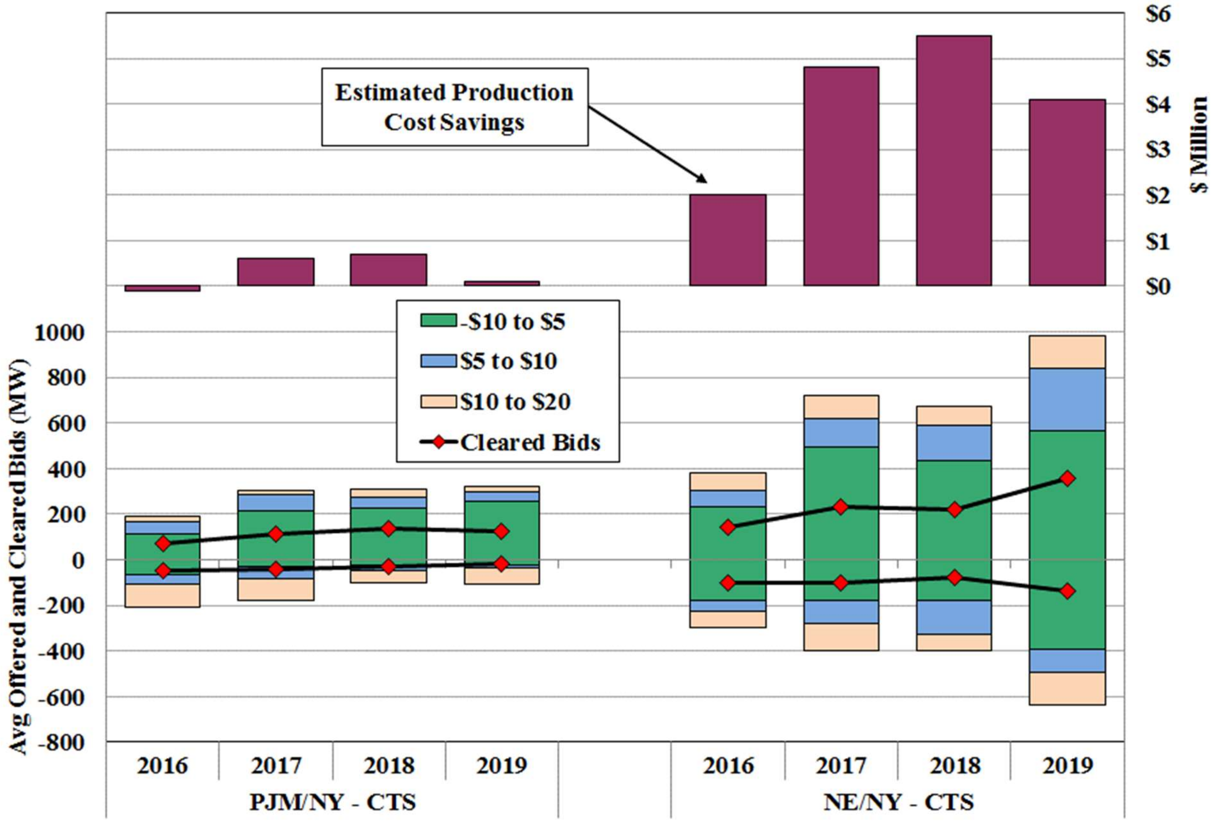
Figure 3 evaluates the overall efficiency of the CTS scheduling process between ISO-NE and the NYISO, compared to the CTS process between PJM and the NYISO. The bottom portion of the figure shows annual average quantities of price-sensitivity of CTS bids for three price ranges and schedules during peak hours (i.e., HB 7 to 22) from 2016 to 2019. Positive numbers indicate export bids from New England or PJM to New York and negative numbers represent import offers from New York to New England or PJM. The upper portion of the figure shows the market efficiency gains (and losses) from CTS, which is measured by production cost savings.[8]

The results in Figure 3 show that the participation of CTS has been much more robust at the NE/NY interface than at the PJM/NY interface. The average amount of price-sensitive bids that were offered and cleared was significantly larger at the NE/NY interface because large transaction fees are imposed at the PJM/NY interface while there are no substantial transmission charges or uplift charges on transactions at the NE/NY interface. Typically, the NYISO charges physical exports to PJM at a rate ranging from \$4 to \$8 per MWh, while PJM charges physical imports and exports a transmission rate and uplift allocation that averages less than \$3 per MWh. These charges are a significant economic barrier to achieving the potential benefits from the CTS process because they deter participants from submitting efficient CTS offers.

The estimated production cost savings from the CTS process between New England and New York averaged \$4 million each year in the past four years, while the estimated savings have been minimal at the PJM/NY interface. In addition to higher price-sensitive bidding volumes, price forecasting improvements were another key contributor to higher savings at the NE/NY interface.

8 Production cost savings are calculated relative to our estimates of scheduling that would have occurred under the previous hourly scheduling process. To estimate the adjustment in the interchange schedule attributable to the intra-hour CTS scheduling process, we compare the final CTS schedule to advisory schedules in NYISO's RTC model that are determined 30 minutes before each hour. This methodology likely captures only a portion of the overall production cost savings from CTS, since it does not account for the efficiency gains that come from traders engaging in spread bidding (i.e., where firms submit a bid that is evaluated relative to the ISO's forecasts) as compared to the previous process where traders submitted a supply offer or export bid at the border.

Figure 3: CTS Scheduling and Efficiency
2016 - 2019



ISO-NE's price forecasting is more accurate than PJM's in part because it forecasts a supply curve (with 7 points representing 7 different interchange levels at the interface), while PJM only forecasts a single price point at one assumed interchange level. Nonetheless, our evaluation of the price forecasting errors at the NE/NY interface indicated that further improvements in price forecasting are possible. The three largest contributors to price forecast errors include:[9]

- Errors in load forecasting and wind forecasting were the largest contributor (23 percent).
- Differences in timing and ramp profiles between forecasting model and dispatch model were the second largest contributor (22 percent).
- Forced outages and poor dispatch performance by generators were the third largest contributor (15 percent).

If the ISOs can address these areas and further improve the price forecasts that underlie the CTS prices, it should ultimately allow the process to achieve larger savings. Therefore, there is ample opportunity to improve the performance of the CTS process at the NE/NY interface. Nonetheless, it is important to note that the CTS process with NYISO is by far the best performing CTS that has been implemented to date (CTS process have been implemented between PJM and both NYISO and MISO).

[9] See Section VI.C in our *2017 Assessment of the ISO New England Electricity Markets*.

II. Competitive Assessment of the Energy Market

This section evaluates the competitive performance of the ISO-NE energy market in 2019. Although LMP markets increase overall system efficiency, they may provide incentives for exercising market power in areas with limited generation resources or transmission capability. Most market power in wholesale electricity markets is dynamic, existing only in certain areas and under particular conditions. The ISO employs market power mitigation measures to prevent suppliers from exercising market power under these conditions. Although these measures have generally been effective, it is still important to evaluate the competitive structure and conduct in the ISO-NE markets because participants with market power may still have the incentive to exercise market power at levels that would not warrant mitigation.

Based on the analysis presented in this section, we identify the geographic areas and market conditions that present the greatest potential for market power abuse. We use a methodology for measuring and analyzing potential withholding that was developed in prior assessments of the competitive performance in the ISO-NE markets.[10] We address four main areas in this section:

- Mechanisms by which sellers exercise market power in LMP markets;
- Structural market power indicators to assess competitive market conditions;
- Potential economic and physical withholding; and
- Market power mitigation.

A. Market Power and Withholding

Supplier market power can be defined as the ability to profitably raise prices above competitive levels. In electricity markets, this is generally done by economically or physically withholding generating resources. Economic withholding occurs when a resource is offered at prices above competitive levels to reduce its output or otherwise raise the market price. Physical withholding occurs when all or part of the output of a resource is not offered into the market when it is available and economic to operate. Physical withholding can be accomplished by "derating" a generating unit (i.e., reducing the unit's high operating limit).

While many suppliers can increase prices by withholding, not every supplier can profit from doing so. Withholding will be profitable when the benefit of selling its remaining supply at prices above the competitive level is greater than the lost profits on the withheld output. In other words, withholding is only profitable when the price impact exceeds the opportunity cost of lost sales for the supplier. The larger a supplier is relative to the market, the more likely it will have the ability and incentive to withhold resources to raise prices.

10 See, e.g., Section VIII, *2013 Assessment of Electricity Markets in New England*, Potomac Economics.

There are several additional factors (other than size) that affect whether a market participant has market power, including:

- The sensitivity of real-time prices to withholding, which can be very high during high-load conditions or high in a local area when the system is congested;
- Forward power sales that reduce a large supplier's incentive to raise prices in the spot market;[11] and
- The availability of information that would allow a large supplier to predict when the market may be vulnerable to withholding.

When we evaluate the competitiveness of the market or the conduct of the market participants, we consider each of these factors, some of which are included in the analyses in this report.

B. Structural Market Power Indicators

This subsection examines structural aspects of supply and demand that affect market power. Market power is of greatest concern in areas where capacity margins are small, particularly in import-constrained areas. Hence, this subsection analyzes the three main import-constrained regions and all New England using the following structural market power indicators:

- Supplier Market Share - The market shares of the largest suppliers determine the possible extent of market power in each region.
- Herfindahl-Hirschman Index ("HHI") - This is a standard measure of market concentration calculated by summing the square of each participant's market share.
- Pivotal Supplier Test - A supplier is pivotal when some of its capacity is needed to meet demand and reserve requirements. A pivotal supplier has the ability to unilaterally raise the spot market prices by raising its offer prices or by physically withholding.

The first two structural indicators focus exclusively on the supply side. Although they are widely used in other industries, their usefulness is limited in electricity markets because they ignore that the inelastic demand for electricity substantially affects the competitiveness of the market.

The Pivotal Supplier Test is a more reliable means to evaluate the competitiveness of energy markets because it recognizes the importance of both supply and demand. Whether a supplier is pivotal depends on the size of the supplier as well as the amount of excess supply (above the demand) held by other suppliers. When one or more suppliers are pivotal, the market may be vulnerable to substantial market power abuse. This does not mean that all pivotal suppliers should be deemed to have market power. Suppliers must have both the ***ability*** and ***incentive*** to raise prices in order to have market power. A supplier must also be able to foresee when it will

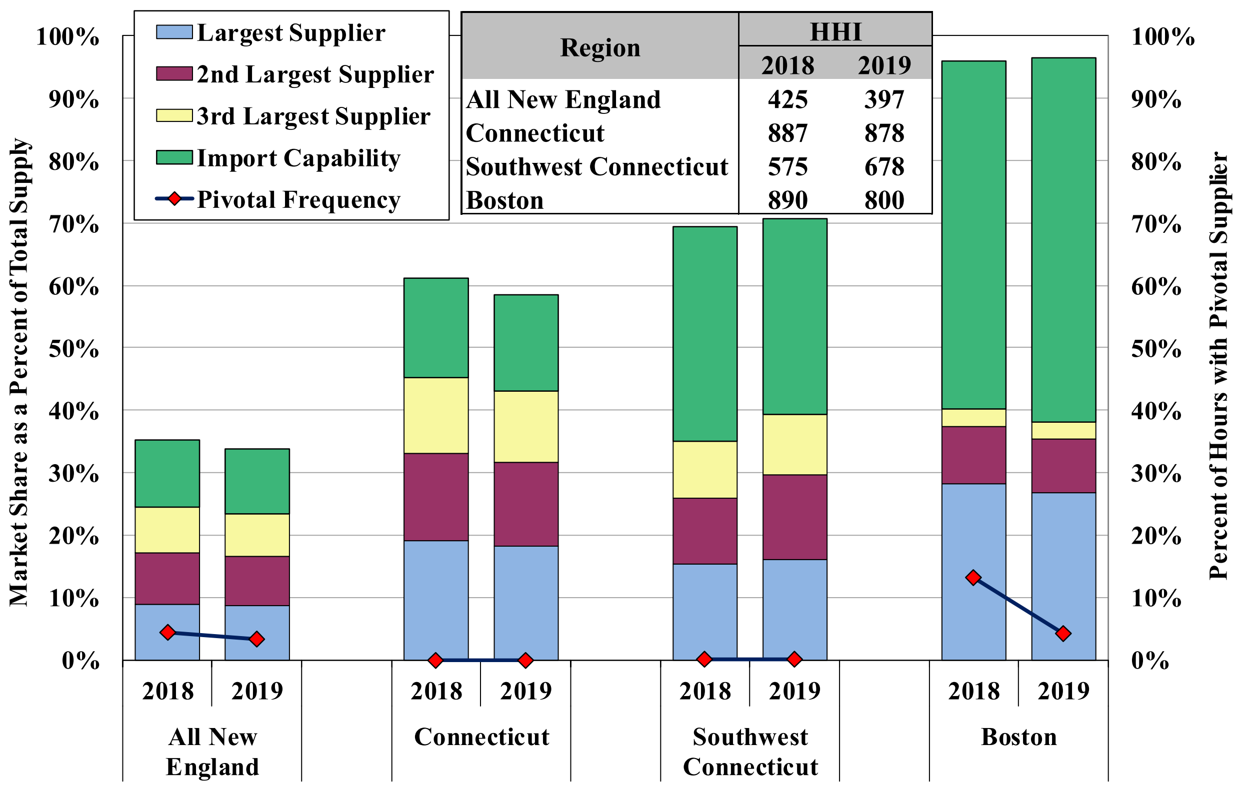
[11] When a supplier's forward power sales exceed the supplier's real-time production level, the supplier is a net buyer in the real-time spot market, and thus, benefits from low rather than high prices. However, some incentive still exists because spot prices will eventually affect prices in the forward market.

be pivotal to exercise market power. In general, the more often a supplier is pivotal, the easier for it to foresee circumstances when it can raise clearing prices. For the supplier to have the incentive to raise prices, it must have other supply that would benefit from higher prices.

Figure 4 shows the three structural market power indicators for four regions in 2018 and 2019. First, the figure shows the market shares of the largest three suppliers and the import capability in each region in the stacked bars.[12,13] The remainder of supply to each region comes from smaller suppliers. The inset table shows the HHI for each region. We assume imports are highly competitive so we treat the market share of imports as zero in our HHI calculation. The red diamonds indicate the portion of hours where one or more suppliers were pivotal in each region. We exclude potential withholding from nuclear units because they typically cannot ramp down substantially and would be costly to withhold due to their low marginal costs.

Figure 4: Structural Market Power Indicators

2018 – 2019



Region	HHI 2018	HHI 2019
All New England	425	397
Connecticut	887	878
Southwest Connecticut	575	678
Boston	890	800

12 The market shares of individual firms are based on information in the monthly reports of Seasonal Claimed Capability("SCC"), available at: https://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/seson-claim-cap. In this report, we use the generator summer capability in the July SCC reports from each year.

13 The import capability shown is the transmission limit from the latest Regional System Plan, available at: https://www.iso-ne.com/system-planning/system-plans-studies/rsp. The Base Interface Limit (or Capacity Import Capability) is used for external interfaces, and the N-1-1 Import Limits are used for reserve zones.

Figure 4 indicates that market concentration of internal generation fell in most regions from 2018 to 2019 primarily because of new entry:

- A new combined-cycle plant (Bridgeport Harbor CC 5) came into full service in mid-2019, adding 500 MW of generating capacity in Southwest Connecticut.
- Three other new generators (Canal 3 and West Medway 4 and 5) entered the market in mid-2019 as well, adding roughly 530 MW of generation supply in Southeast Massachusetts.

Although the portfolio sizes of the three largest suppliers in all New England changed little from 2018 to 2019, their market shares were diluted because of the new entry from other suppliers and market concentration fell slightly as a result. The figure also shows variations in the number of suppliers with large market shares across the four areas. In 2019, Boston had one supplier with a large market share of 27 percent, while all New England has three suppliers with market shares of less than 10 percent each.

Import capability accounts for a significant share of total supply in each region (ranging from 10 percent in all New England to 58 percent in Boston), so the market concentration (measured by the HHI) was relatively low, well under 1000 in all of the four areas. In Boston, there was little change in internal generating capacity, but market concentration fell as the import capability increased in 2019 because of transmission upgrades.[14]

In general, HHI values above 1800 are considered highly concentrated by the U.S. Antitrust Agencies and the FERC for purposes of evaluating the competitive effects of mergers. However, this does not establish that there are no market power concerns. These concerns are most accurately assessed in our pivotal supplier analysis for 2019, which indicates that:

- In Southwest Connecticut and Connecticut, there were very few hours (< 0.05 percent) when a supplier was pivotal in 2019.
- In Boston, one supplier owned 64 percent of the internal capacity, but was pivotal in just 4 percent of hours in 2019. This underscores the importance of import capability into constrained areas in providing competitive discipline; and
- In all New England, at least one supplier was pivotal in 3.5 percent of hours in 2019.[15]

The pivotal frequency continued to fall over the past three years in all New England (from 13 percent in 2017) because of new market entry in 2018 (over 1.5 GW) and 2019 (over 1 GW).

14 The N-1-1 import capability into Boston is increased by more than 400 MW because of the completion of transmission upgrades in the Greater Boston Reliability Project in mid-2019.

15 The pivotal supplier results are conservative for “All New England” compared to those evaluated by the IMM (see their 2018 SOM report, Section 3.7.3) primarily because of our differences in: (a) treatment of portfolios with nuclear generation; (b) assumptions about supply availability; and (c) frequency of pivotal evaluation. See the memo, “Differences in Pivotal Supplier Test Results in the IMM’s and EMM’s Annual Market Assessment Reports”, NEPOOL Participants Committee Meeting, December 7, 2018.

Other key factors contributing to the decrease in pivotal supplier frequency from 2018 to 2019 included:

- Load levels falling by an average of 4 percent from 2018 to 2019; and
- Price-responsive demand resources starting to participate in the energy market in June 2018, satisfying a significant portion of reserve requirements.

Similarly, the pivotal frequency fell in Boston from 28 percent in 2017 to 13 percent in 2018 and 4 percent in 2019. The entry of the Footprint power plant in 2018 contributed to this decrease and led to less frequent commitments of the Mystic facilities in the portfolio of the largest supplier in Boston. The increase in the import capability in 2019 reduced the reliance on the internal generation, contributing to the reduction in 2019.

In spite of the reduction in pivotal frequency, the results in Boston and all New England still warrant further review to identify potential withholding by suppliers in these regions. This review is provided in the following section, which examines the behavior of pivotal suppliers under various market conditions to assess whether the conduct has been consistent with competitive expectations.

C. Economic and Physical Withholding

Suppliers that have market power can exercise it by economically or physically withholding resources as described above. We measure potential economic and physical withholding by using the following metrics:

- Economic withholding: we estimate an "output gap" for units that produce less output because they have raised their economic offer parameters (start-up, no-load, and incremental energy) significantly above competitive levels. The output gap is the difference between the unit's capacity that is economic at the prevailing clearing price and the amount that is actually produced by the unit.[16] This may overstate the potential economic withholding because some of the offers included in the output gap may reflect legitimate supplier responses to operating conditions, risks, or uncertainties.
- Physical withholding: we analyze short-term deratings and outages because they are most likely to reflect attempts to physically withhold resources because it is generally less costly to withhold a resource for a short period of time. Long-term outages typically result in larger lost profits in hours when the supplier does not have market power.

The following analysis shows the output gap results and physical deratings relative to load and participant characteristics. The objective is to determine whether the output gap and/or physical deratings increase when factors prevail that increase suppliers' ability and incentive to exercise market power. This allows us to test whether the output gap and physical deratings vary in a manner consistent with attempts to exercise market power.

16 To identify clearly economic output, the supply's competitive cost must be less than the clearing price by more than a threshold amount - $25 per MWh for energy and 25 percent for start-up and no load costs.

Because the pivotal supplier analysis raises competitive concerns in Boston and all New England, Figure 5 shows the output gap and physical deratings by load level in these two regions. The output gap is calculated separately for:

- Offline quick-start units that would have been economic to commit in the real-time market (considering their commitment costs); and
- Online units that can economically produce additional output.

Our physical withholding analyses focus on:

- Short-term forced outages that typically last less than one week; and
- "Other Derates" that includes reductions in the hourly capability of a unit that is not logged as a forced or planned outage. The "Other Derates" can be the result of ambient temperature changes or other legitimate factors.

Finally, the results in Figure 5 are shown as a percentage of suppliers' portfolio size for the largest suppliers versus the other suppliers. In Boston, we include only the largest supplier in this comparison, who owned 64 percent of internal generating capacity in 2019. In all New England, we compare the three largest suppliers, who collectively owned 26 percent of internal generating capacity in 2019, to all other suppliers.

Figure 5: Average Output Gap and Deratings by Load Level and Type of Supplier
Boston and All New England, 2019

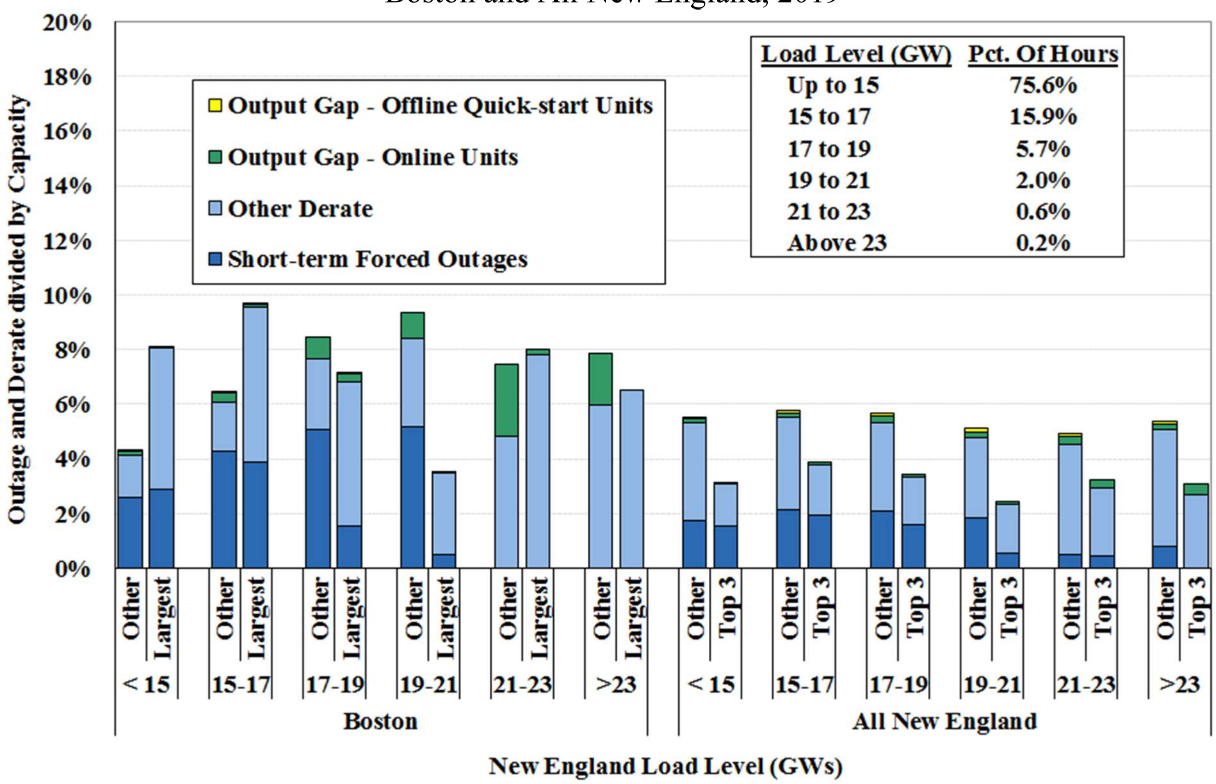


Figure 5 shows that the amount of "Other Derate" was usually higher than other categories. This was primarily because some combined-cycle capacity was often offered and operated in a configuration that reduced its available capacity during off-peak hours. This is generally efficient and does not raise significant competitive concerns. Additionally, the Other Derate category increases for all classes of supplier in the highest load hours (above 21 GW). This is a very small number of hours during the summer when hot temperatures tend to reduce the ratings of thermal generators.

Excluding the contributions of the Other Derates for the reasons described above, the overall output gap and deratings were not significant as a share of the total capacity in either Boston and all New England during 2019. The total amount of output gap and short-term deratings generally fell as load levels increased to the highest levels, which is a good indication that suppliers tried to make more capacity available when the capacity needs were the highest. In addition, the largest suppliers in both Boston and all New England generally exhibited lower levels of overall output gap and deratings, particularly at higher load levels when prices are most sensitive to potential withholding. The output gap continues to be very low across a wide range of conditions.

Overall, these results indicate that the energy market performed competitively in 2019 and did not raise significant concerns about withholding to raise market clearing prices.

D. Market Power Mitigation

Mitigation measures are intended to mitigate abuses of market power while minimizing interference with the market when it is workably competitive. The ISO-NE applies a conduct-impact test that can result in mitigation of a participant's supply offers (i.e., incremental energy offers, start-up and no-load offers). The mitigation measures are only imposed when suppliers' conduct exceeds well-defined conduct thresholds above a unit's reference levels and when the effect of that conduct on market outcomes exceeds well-defined market impact thresholds. This framework prevents mitigation when it is not necessary to address market power, while allowing high prices during legitimate periods of shortage.

The market can be substantially more concentrated in import-constrained areas, so more restrictive conduct and impact thresholds are employed in these areas than market-wide. The ISO has two structural tests (i.e., Pivotal Supplier and Constrained Area Tests) to determine which of the following mitigation rules are applied: [17]

- Market-Wide Energy Mitigation ("ME") – ME mitigation evaluates the incremental energy offers of online resources. This is applied to any resource whose Market Participant is a pivotal supplier.

[17] See Market Rule 1, Appendix A, Section III.A.5 for details on these tests and thresholds.

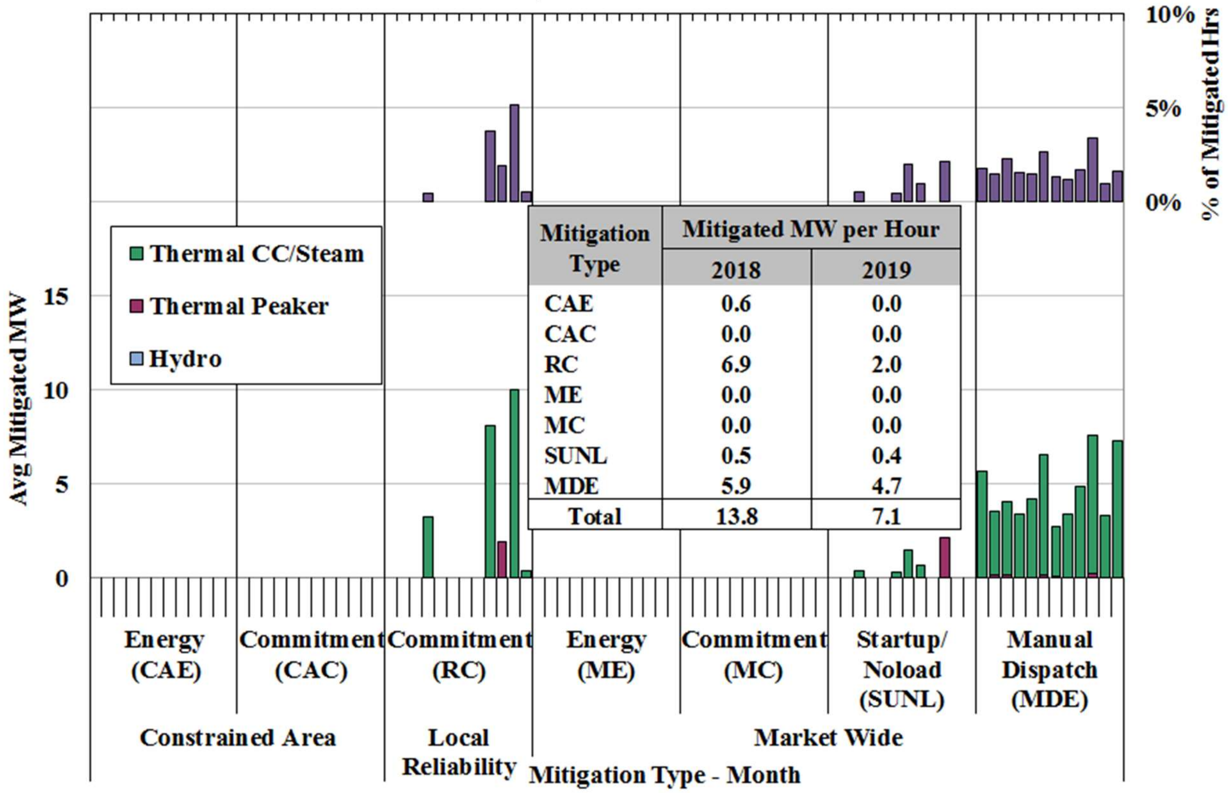
- Market-Wide Commitment Mitigation (“MC”) – MC mitigation evaluates commitment offers (i.e., start-up and no-load costs). This is applied to any resource whose Market Participant is a pivotal supplier.
- Constrained Area Energy Mitigation (“CAE”) – CAE mitigation is applied to resources in a constrained area.
- Constrained Area Commitment Mitigation (“CAC”) – CAC mitigation is applied to a resource that is committed to manage congestion into a constrained area.
- Local Reliability Commitment Mitigation (“RC”) – RC mitigation is applied to a resource that is committed or kept online for local reliability.
- Start-up and No-load Mitigation (“SUNL”) – SUNL mitigation is applied to any resource that is committed in the market.
- Manual Dispatch Mitigation (“MDE”) – MDE mitigation is applied to resources that are dispatched out of merit above their Economic Minimum Limit levels.

There are no impact tests for the SUNL mitigation, the MDE mitigation, and the three types of commitment mitigation (i.e., MC, CAC, and RC), so suppliers are mitigated if they fail the conduct test in these five categories. This is reasonable because this mitigation is only applied to uplift payments, which usually rise as offer prices rise, so, in essence, the conduct test is serving as an impact test as well for these categories. When a generator is mitigated, all offer cost parameters are set to their reference levels for the entire hour.

Figure 6 examines the frequency and quantity of mitigation in the real-time energy market during each month of 2019. Any mitigation changes made after the automated mitigation process were not included in this analysis (because these constitute a very small share of the overall mitigation). The upper portion of the figure shows the portion of hours affected by each type of mitigation. If multiple resources were mitigated during the same hour, only one hour was counted in the figure. The lower portion of the figure shows the average mitigated capacity in each month (i.e., total mitigated MWh divided by total numbers of hours in each month) for each type of mitigation and for three categories of resources: hydroelectric units, thermal peaking units, and thermal combined cycle and steam units. The inset table compares the annual average amount of mitigation for each mitigation type between 2018 and 2019.

Mitigation was relatively infrequent in 2019, occurring in less than 2 percent of all hours. Nearly all mitigation in the real-time market was for either local reliability commitment or manual dispatch energy. Both typically occurred more frequently during non-peak periods (e.g., shoulder months) because of higher local reliability needs that were often caused by planned transmission outages. The high proportion of mitigation in these categories is expected because local reliability areas raise the most significant potential market power concerns and are mitigated under the tightest thresholds. In general, these two categories of mitigation only affect NCPC payments and have little impact on energy or ancillary service prices. The occurrence of mitigation in these two categories fell nearly 50 percent from 2018 to 2019, partly because of reduced needs in local areas that were attributable to lower load levels in 2019.

Figure 6: Frequency of Real-Time Mitigation by Mitigation Type and Unit Type
By Month, 2019



Although local reliability mitigation has the tightest threshold (10 percent) among all types of mitigation, it is not fully effective because suppliers sometimes have the latitude and incentive to operate in a more costly mode and receive larger NCPC payments as a result. For example, combined-cycle units needed for reliability that can offer in a multi-turbine configuration or in a single-turbine configuration often do not offer in the single-turbine configuration when they are likely to be needed for local reliability. By offering in a multi-turbine configuration, these units receive higher NCPC payments. Likewise, generators are sometimes not required to burn the lowest-cost fuel. In previous years, substantial amounts of NCPC uplift was paid to dual-fuel units burning oil when natural gas was much less expensive. This was not a significant issue in 2019. We discuss these two issues in more detail in Section III and continue to recommend that the ISO consider tariff changes that would expand its authority to address these issues.

The appropriateness of mitigation depends on accurate generator cost estimates (i.e., "reference levels"). If reference levels are too high, suppliers may be able to inflate prices and/or NCPC payments above competitive levels. If reference levels are too low, suppliers may be mitigated below cost, which could suppress prices below efficient levels. It can be difficult to estimate costs accurately for several types of generator, including:

- *Energy-limited hydroelectric resources*. The units' costs are almost entirely opportunity costs (the trade-off of producing more now and less later). These costs are generally difficult to accurately reflect.
- *Oil-fired resources*. They become economic when gas prices rise above oil prices, but have limited on-site oil inventory. The suppliers may raise their offer prices to conserve the available oil in order to produce during the periods with potentially the highest LMPs.
- *Gas-fired resources during periods of tight gas supply*. Volatile natural gas prices, particularly in the winter, create uncertainty regarding fuel costs that can be difficult to reflect accurately in offers and reference levels. The uncertainty is increased by the fact that offers and reference levels for the day-ahea market must be determined by 10 am on the prior day.

Appropriately recognizing opportunity costs in resources' reference levels reduces the potential for inappropriate mitigation of competitive offers, helps the region conserve limited fuel supplies, and improves the overall efficiency of scheduling for fuel-limited resources. ISO-NE has recognized this issue and developed a model to estimate an opportunity cost for oil-fired and dual-fuel generators with short-term fuel supply limitations to include in their reference prices. The model estimates opportunity costs by forecasting the profit-maximizing generation schedule for each unit with limited fuel supply over a rolling seven-day period, as well as the opportunity cost adder that would be required to limit its generation accordingly.

This model has been used since December 2018. Because both the 2018/19 winter and the 2019/20 winter were mild, the use of oil was limited in these two winter periods and oil inventory has been sufficient throughout both winters. Therefore, the effectiveness of the opportunity cost estimator has not yet been challenged by tight market conditions. Nonetheless, this reference calculation enhancement should help address fuel security issues that ISO-NE faces by allowing generators to conserve fuel more effectively with their offers in the future.

E. Competitive Performance Conclusions

The pivotal supplier analysis suggests that structural market power concerns diminished noticeably in Boston and in all New England in 2018 and 2019, driven largely by the new entry of more than 2.5 GW of generating capacity over the past two years and transmission upgrades in Boston. Our analyses of potential economic and physical withholding also find that the markets performed competitively with no significant evidence of market power abuses or manipulation in 2019.

In addition, we find that the market power mitigation rules have generally been effective in preventing the exercise of market power in the New England markets. The automated mitigation process helps ensure the competitiveness of market outcomes by mitigating attempts to exercise market power in the market software before it can affect the market outcomes. To ensure competitive offers are not mitigated, generators can proactively request reference level adjustments when they experience input cost changes due to fuel price volatility or other factors. Hourly offers enable generators to modify their offers to reflect changes in their marginal costs and for the ISO to set reference levels that properly reflect these costs.

The ISO has implemented a procedure to calculate an opportunity cost for oil-fired and dual-fuel generators with limited fuel inventories to be incorporated in their reference prices. This enhancement should lead to more efficient scheduling of energy-limited resources. However, its effectiveness was not truly tested because of relatively mild winter conditions. We will continue monitor this and evaluate how the opportunity cost estimator performs particularly under prolonged severe winter weather conditions.

Nonetheless, we find one area where the mitigation measures may not have been fully effective. This relates to resources that are frequently committed for local reliability. Although the mitigation thresholds are tight for these resources, the suppliers have the incentive to operate in a higher-cost mode and receive higher NCPC payments as a result. Hence, we recommend the ISO consider changes that would address this concern.

III. Commitments for Relibility Needs and NCPC Charges

To maintain system reliability, sufficient resources must be available in the operating day to satisfy forecasted load and operating reserve requirements, both at the system level and in local load pockets. The day-ahead market is intended to provide incentives for market participants to make resources available to meet these requirements at the lowest cost. Satisfying reliability requirements in the day-ahead market is more efficient than waiting until after the day-ahead market clears because reliability commitments affect which resources should be committed economically in the day-ahead market.

The ISO commits resources within the day-ahead market scheduling process to satisfy two types of reliability requirements that are not are reflected in the market clearing prices. It commits:

- Local second contingency protection resources to ensure the ISO is able to reposition the system in key areas in response to the second largest contingency after the first largest contingency has occurred;
- Resources to satisfy system-level operating reserve requirements in the day-ahead market.

In its Energy Security Initiative (ESI), the ISO is taking a major step towards addressing these reliability requirements through market-based procurement (rather than out-of-market actions). Under the ESI, the ISO is proposing to incorporate system-level reserve requirements in its day-ahead market starting in 2024. The ESI will address many of the issues raised in this section.

Currently, these local and system-level reserve requirements are not enforced in the day-ahead market pricing software. Consequently, generators are frequently committed in the day-ahead market to satisfy local and systemwide reserve requirements, but the clearing prices of energy (and reserves) are understated because they do not reflect the costs of satisfying these requirements.

In addition, since the day-ahead market schedules resources to satisfy load bids rather than forecast load, the ISO must sometimes commit additional generators with high commitment costs after the day-ahead market to satisfy forecast load and reserve requirements. Such commitments generate costs that are uplifted to the market and depress real-time market prices, leading to additional uplift and undermining incentives sastify the reserve requirements.

When resources are scheduled at clearing prices that are not sufficient for them to recoup their full as-bid costs, ISO-NE provides an NCPC payment to cover the revenue shortfall. Although the overall size of NCPC payments are small relative to the overall New England wholesale market, NCPC payments are important because they usually occur when the market requirements are not fully aligned with the system's reliability needs or prices are otherwise not fully efficient.

This section evaluates these reliability commitments and resultant NCPC charges and discusses implications for market efficiency. It is divided into subsections that address:

- Commitment for system-level operating reserve requirements;
- Commitment for forecasted system-level energy and reserve requirements; and
- Commitment for local second contingency protection requirements.

The final subsection provides a summary of our conclusions and recommendations. It also discusses the ways in which the ISO's recent proposal to create day-ahead operating reserve markets will address the issues analyzed in this section.

A. Day-Ahead Commitment for System-Level Operating Reserve Requirements

The day-ahead market software commits sufficient resources to satisfy system-level operating reserve requirements in addition to energy schedules. However, these reserve requirements are not enforced in the day-ahead market dispatch or pricing software because ISO-NE does not have day-ahead reserve markets. Consequently, generators are frequently committed in the day-ahead market to satisfy reserve requirements, but the clearing prices of energy (and reserves) are understated because they do not reflect the costs of satisfying the reserve requirements.

Table 3 summarizes the additional commitments to satisfy the system-level 10-minute spinning reserve requirements in the past three years by showing our estimates of:

- The total number of hours in each year during which such commitments occurred;
- The average capacity (i.e., the Economic Max of the unit) committed over these hours;
- The total amount of NCPC uplift charges incurred; and
- The NCPC uplift charge rate (i.e., NCPC uplift per MWh of committed capacity)

Table 3: Day-Ahead Commitment for System 10-Minute Spinning Reserve Requirement
2017 - 2019

Year	# Hours	Average Capacity Committed per Hour (MW)	DA NCPC (Million $)	Uplift Rate ($/MWh)
2017	4901	680	$ 10.1	$ 3.05
2018	3868	628	$ 8.0	$ 3.29
2019	3774	580	$ 4.2	$ 1.92

The table shows that additional generating capacity was committed to satisfy the system-level 10-minute spinning reserve requirement in 43 to 56 percent of all hours over the past three years. This was the second largest contributor to the NCPC uplift charges in the day-ahead market each year. The uplift cost per MWh of committed capacity ranged from roughly $2 to $3 per MWh, indicating that pricing these operating reserve requirements in the day-ahead market would provide additional (and more efficient) compensation for resources providing 10-minute spinning reserves.

We found very few hours each year when additional capacity was committed to satisfy the total 10-minute reserve and 30-minute reserve requirements. This is likely because New England has had sufficient offline fast start capacity to satisfy these requirements in most hours.

Setting more efficient prices for energy and spinning reserves would provide better incentives for reliable performance, flexibility, and availability. This will become increasingly important as the penetration of intermittent renewable generation increases over the coming decade. Under-compensating generators that have flexible characteristics is undesirable because it will shift investment incentives towards other types of resources and increase dependence on the capacity market for attracting the investment necessary to maintain reliability. Accordingly, the ISO recently proposed to address these market deficiencies as part of its Energy Security Improvements project by implementing a comprehensive set of operating requirements that will be co-optimized with the clearing of energy in the day-ahead market. We strongly support the ISO's proposed improvements and discuss them in the following subsection.

B. Commitment for Forecasted System-level Energy and Reserve Requirement

The day-ahead market clears physical and virtual load bids and supply offers, and produces a coordinated commitment of resources. When the day-ahead market does not satisfy all forecasted reliability requirements (i.e., forecasted needs of energy plus operating reserves) for the operating day, the ISO performs the Reserve Adequacy Assessment (RAA) to ensure sufficient resources will be available. However, such commitments typically generate expenses that are uplifted to the market and increase the amount of supply available in real time. This depresses real-time market prices, leads to additional uplift, and undermining market incentives for suppliers to satisfy the system's requirements.

The supplemental commitments for forecasted system-level energy and reserve needs were infrequent in 2019. The ISO made such commitments on just 11 days.[18] The committed capacity totaled nearly 1,900 MW on one day because of a force majeure on the Iroquois pipeline, and it averaged 270 MW each day on the other 10 days. Therefore, the market impact of these supplemental commitments were not very significant in 2019. Nonetheless, it is still important to minimize such after-day-ahead-market commitments because satisfying reliability requirements in the day-ahead market is more efficient for the reasons discussed earlier.

In addition, the rising demand for natural gas in recent years has reduced the availability of gas to electricity generators during severe winter weather conditions, creating new challenges for the design of wholesale electric markets. The primary challenge is for the market to coordinate the

18 See "*Operator Initiated Commitments*" reports, published on the ISO-NE public website.

scheduling of electric resources in a manner that satisfies the system's reliability needs and leads to efficient and timely procurement and scheduling of natural gas and other fuels, both for electric generation and other uses. The day-ahead market is intended to provide such incentives for market participants to ensure their resources are available for the next operating day.

The ISO has proposed new market-based solutions to address these issues in its Energy Security Improvements Project.[19] The ISO has proposed to procure the following reserve products in the day-ahead market:

- Generation Contingency Reserves ("GCR") – including reserve capability deployable within 10 minutes and 30 minutes. This is the day-ahead version of the operating reserves requirements that are currently procured in the real-time market. These will address the commitments for 10-minute spinning reserves that are discussed in Subsection A.
- Replacement Energy Reserves ("RER") – including reserve capability deployable within 90 minutes and 240 minutes to be able to restore operating reserves consistent with NERC/NPCC restoration time standards.
- Energy Imbalance Reserves ("EIR") – including additional capability to cover the load-balance gap. Forecast Energy Requirement ("FER") frequently exceeds the total physical energy supply cleared in the day-ahead energy market. Currently, this requirement is satisfied in the RAA process, and it will be brought into the day-ahead market.

We have evaluated how these new reserve requirements might affect the day-ahead market by analyzing the availability of reserves on each day during 2019. Figure 7 assesses how often the forecasted energy and total 240-minute reserve requirement could have been satisfied by available capacity on each day of 2019. The figure summarizes the total available capacity that was not scheduled for energy in the day-ahead market but that was offering to be available within 4 hours in the following categories:

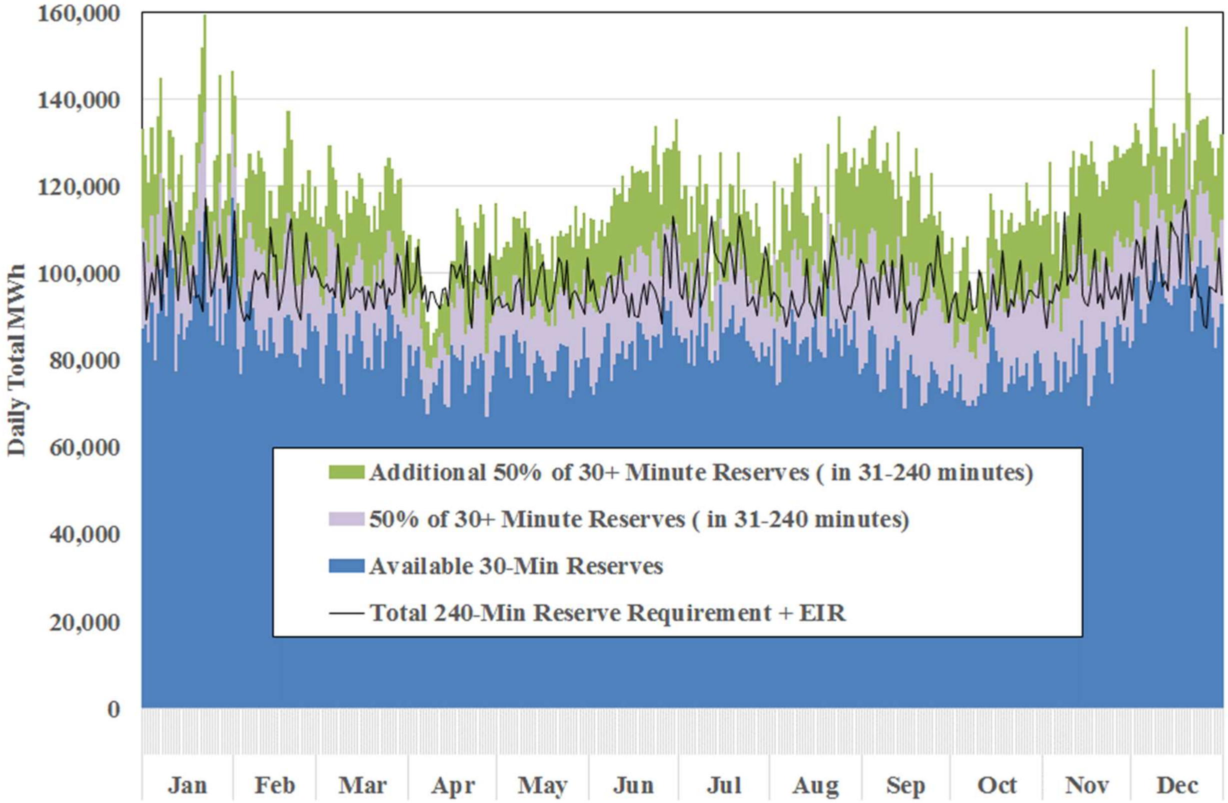
- Available 30-Minute Reserves – This includes the headroom of online capacity that is rampable in 30 minutes and offline capacity from available fast-start resources (the blue area).
- Available 30+ Minute Reserves – This includes the headroom of online capacity that is rampable beyond 30 minutes and offline capacity from available non-fast-start resources that are capable of providing energy in 4 hours (i.e., the Cold Start Up Time + Cold Notification Time < 4 hours). Capacity in this category is shown with two equal halves in the figure (the purple and green areas).
- The total 240-Minute Reserve Requirement Plus Additional Energy Imbalance Reserve Requirement – This represents the required total amount of reserve capability to meet the forecasted energy and reserve needs for each operating day (the black line).

The daily total MWh of the capacity for energy limited resources (e.g., pump-storage units) is limited by its maximum daily energy capability less scheduled energy MWh in the day-ahead

19 See *Energy Security Improvements: Create Energy Options for New England*, April 30, 2020.

market, since such fuel constraints could limit the number of hours in which some units could be relied upon to provide reserves.

Figure 7: Available Capacity for Daily Forecasted Reliability Requirement
2019



The figure shows that if there were no explicit procurements of the three new reserve products, available 30-minute reserve capability (the only secured reserve capability in the current day-ahead market) would have not been sufficient to satisfy the forecasted energy and reserve requirement on the vast majority of days in 2019. There was usually enough generating capacity submitting offers to be available within 4 hours to satisfy the forecasted energy and reserve needs. However, the actual availability of these resources on each day is uncertain because they had no day-ahead reserve obligations to pre-arrange fuel and may have difficulty obtaining fuel on short notice if needed.

We estimated that the forecasted energy and reserve requirements would not have been satisfied on 142 days if the additional capacity (rampable in 31 to 240 minutes) had been only 50 percent available on the next operating day. The number of deficient days would fall to 50 if 75 percent of the capacity was available. This reinforces the importance of securing needed physical capacity for forecasted reliability needs through markets, which will provide greater incentive and proper compensation for resources to make their capacity available on the operating day (e.g., procuring fuel necessary for day-ahead reserve obligations).

The figure also shows that, even with the assumption of 100 percent availability, the overall capacity margin would have been relatively small on most days, and small deficiencies would have occurred on 20 days. The estimated capacity margin could be smaller in future years because of several factors.

- Our estimates do not reflect energy limitations on certain gas-fired resources that face pipeline gas limitations.
- The winter in 2019 was very mild, reducing the severity of energy limitations on fossil-fired units.
- The resource mix may change in the coming years with retirements of fossil-fired units and new entry of renewable resources. Higher penetration of renewable resources will also increase the reserve requirement.

Therefore, it is very important to have a market mechanism that will provide transparent and efficient price signals that reflect underlying reliability needs and provide greater incentives for market participants to ensure their capacity available on the operating day with greater certainty.

In addition, the figure shows that the capacity margin is generally smaller outside the winter period, particularly during shoulder months when the availability of generating capacity is lowered by more generation maintenance outages. The 20 deficient days with the assumption of 100 percent availability are all outside the winter season. This stresses the importance of having the day-ahead market commit resources to satisfy the forecasted energy and reserve requirements for each and every operating day.

C. Day-Ahead Commitment for Local Second Contingency Protection

Most reliability commitments for local second contingency protection occur in the day-ahead market. While these commitments may be justified from a reliability perspective, the underlying local requirements are not enforced in the day-ahead market pricing software. As a result, they can lead to inefficient prices and concomitant NCPC uplift. Most NCPC charges for local reliability commitments are incurred in the day-ahead market rather than the real-time market (as is the case for most other RTOs). These local commitments have been the largest contributor to NCPC charges in the day-ahead market in the recent years.

Table 4 summarizes the commitments for the local second contingency in the day-ahead market in the past three years by showing:

- The total number of hours in each year during which such commitments occurred;
- The average capacity (i.e., the Economic Max of the unit) committed over these hours;
- The total amount of NCPC uplift charges incurred;
- The NCPC uplift charge rate (i.e., NCPC uplift per MWh of committed capacity); and
- The implied marginal value of local reserves that was not reflected in market clearing prices aggregated over the year.

Although the table shows these numbers by load zone based on the location of the committed units, the commitment may actually satisfy the local second contingency requirement in a broader region or in a subarea of the load zone.

Table 4: Day-Ahead Commitment for Local Second Contingency and NCPC Charges
2017 – 2019

Year	Zone	# Reliability Commitment Hours	Average Committed Capacity per Hour (MW)	DA NCPC (Million $)	Uplift Rate ($/MWh)	Implied Marginal Reserve Value ($/kW-Year)
2017	Maine	277	358	$ 1.2	$ 12.02	$ 3.33
	New Hampshire	36	47	$ 0.03	$ 18.24	$ 0.66
	Connecticut	103	330	$ 0.5	$ 14.69	$ 1.51
	Rhode Island	28	300	$ 0.1	$ 8.79	$ 0.25
	SE Mass	53	325	$ 0.5	$ 29.33	$ 1.55
	NEMA/Boston	641	615	$ 9.0	$ 22.85	$ 14.64
2018	Maine	302	366	$ 1.1	$ 9.83	$ 2.97
	New Hampshire	417	53	$ 0.5	$ 23.11	$ 9.64
	Connecticut	26	44	$ 0.02	$ 19.58	$ 0.51
	Rhode Island	78	270	$ 0.2	$ 7.75	$ 0.60
	SE Mass	298	256	$ 0.7	$ 9.46	$ 2.82
	NEMA/Boston	526	667	$ 9.9	$ 28.32	$ 14.89
2019	Maine	980	360	$ 2.7	$ 7.62	$ 7.47
	New Hampshire	354	67	$ 0.5	$ 21.97	$ 7.78
	Rhode Island	154	289	$ 0.3	$ 5.73	$ 0.88
	SE Mass	633	276	$ 3.1	$ 17.81	$ 11.27
	WC Mass	43	236	$ 0.2	$ 16.52	$ 0.71
	NEMA/Boston	46	540	$ 0.2	$ 7.71	$ 0.35

The Boston area used to account for the most frequent commitments and the vast majority of NCPC uplift in this category. This was greatly reduced in 2019 because of the addition of new generating capacity and transmission upgrades in the Boston area. Nonetheless, units in other areas, particularly Maine and SEMA, are still frequently committed for local second contingency protection. Although Maine generally exports to other areas, operating reserves are still required to ensure local reliability in case two large contingencies were to occur. The reliability commitments in Maine increased in 2019 during periods of transmission outages to support planned transmission work.

The uplift cost per MWh of committed capacity ranged from roughly $8/MWh on units in Maine to $22/MWh on units in New Hampshire, indicating inefficient market clearing prices for at least two reasons:

- First, the units receiving NCPC payments systematically receive more revenues than lower-cost resources.
- Second, the costs of these resources will not be reflected in the prices of the operating reserves that are also satisfying the underlying reliability requirement.

These two issues distort economic incentives in favor of high-cost units with less flexible characteristics because, all else equal, they receive higher revenue than lower-cost more flexible units. The final column shows that if all reserves providers in the area received the implied marginal value of local reserves, it would result in up to $7.50 per kW-year of additional revenue for a unit in Maine and $7.80 per kW-year for a unit in New Hampshire. Hence, when local NCPC is substantial, it is important to identify the underlying causes and consider market reforms as needed to improve the efficiency of prices for energy and operating reserves in local areas. Satisfying local requirements through a day-ahead operating reserve market would substantially reduce the need to commit resources out-of-market in the local areas that currently receive sizable NCPC payments.

These concerns are exacerbated because some generators that are committed for local second contingency protection offer as a multi-turbine group, requiring the ISO to commit multiple turbines when one turbine would be sufficient. Needlessly committing the multi-turbine configuration displaces other more efficient generating capacity. In 2019, multi-turbine combined-cycle commitments accounted for: (a) more than 40 percent of the capacity committed for local reliability in the day-ahead market; and (b) roughly 35 percent of day-ahead local second contingency NCPC payments. The ISO could avoid excess commitment by modifying its tariff to require capacity suppliers to offer multiple unit configurations to allow the ISO to commit just one turbine at a multi-turbine group. This would improve market incentives for flexibility and availability. Directing more revenue to generators that have these characteristics would shift investment accordingly and reduce reliance on the capacity market for attracting investment to local areas.

Likewise, reliance on NCPC payments provides adverse fuel procurement incentives. Under the market power mitigation rules, a generator that is committed for reliability can make more money by operating on a more expensive fuel because the relevant offer cap is calculated as a percentage over the generator's estimated cost.[20] Enforcing a requirement that generators committed for reliability burn the most economic fuel will reduce the frequency of commitments that require substantial NCPC payments. Ultimately, this will improve price signals for energy and reserves, and lower costs for the ISO's customers.

D. Conclusions and Recommendations

In our assessment of day-ahead reliability commitment, we found that in 2019:

- Supplemental commitment to satisfy the system-level 10-minute spinning reserve requirement occurred in roughly 3,800 hours, leading to more than $4 million (or 33 percent) of day-ahead NCPC.

[20] See Section III.A.5.5.6.2. of the ISO Tariff.

- Commitment for local second contingency protection occurred in roughly 1,800 hours, leading to nearly $7 million (or 54 percent) of day-ahead NCPC.

Both of these requirements are satisfied by scheduling operating reserves, but operating reserves are not procured in the day-ahead market and the cost of scheduling operating reserves is not reflected efficiently in energy prices. As a result, resources that provide these services are often undervalued. The resulting NCPC uplift per MWh of committed capacity ranged from:

- Roughly $8 to $22/MWh in local regions for second contingency commitment; and
- Approximately $2 to $3/MWh for system-level 10-minute spinning reserve commitment.

In addition, we continue to find that NCPC costs are inflated when the ISO is compelled to start combined-cycle resources in a multi-turbine configuration when its reliability needs could have been satisfied by starting them in a single-turbine configuration. In 2019, multi-turbine combined-cycle commitments accounted for more than 40 percent of the capacity committed for local reliability in the day-ahead market.

ISO-NE has started several initiatives to address energy security concerns, including introducing three new reserve products (i.e., GCR, RER, and, EIR) into the day-ahead market, which will be co-optimized with energy procurement. Our assessment suggests that:

- The available capacity capable of providing 30-minute reserves was not sufficient to satisfy the forecasted energy and reserve requirement (i.e, GCR + RER + EIR) on almost every day of 2019.
- The procurement and pricing of these ancillary services in the day-ahead market will provide greater incentives for market participants to procure fuel necessary for day-ahead reserve obligations, thus improving energy security.
- The capacity margin to satisfy the forecasted energy and reserve requirement was small on many days and could beome smaller in the coming years because of retirements of fossil-fired units and higher penetration of renewable resources.
- It would be valuable to procure these ancillary services in the day-ahead market for the forecasted energy and reserve requirement exists not just in the winter season but also during other months.

Therefore, we support the EIS effort by the ISO, which will substantially address these concerns. We also make two recommendations to improve the pricing of energy and operating reserves.

- We recommend that the ISO expand its authority to commit combined-cycle units in a single-turbine configuration when that will satisfy its reliability need.
- We recommend that the ISO co-optimize the scheduling and pricing of operating reserves in the day-ahead market, including the operating reserves needed to satisfy the local second contingency requirement.

IV. Long-Term Investment Signals

A well-functioning wholesale market establishes transparent and efficient price signals that guide investment and retirement decisions for generation and transmission. Wholesale prices motivate firms to invest in new resources, maintain existing generation, and/or retire older units. Even for new investment that is primarily motivated by state policy through competitive solictiations by state agencies, wholesale prices strongly influence the particular locations and technologies of projects that are ultimately selected.

In this section, we evaluate the investment incentives for various resource technologies in ISO-NE, focusing on the following issues:

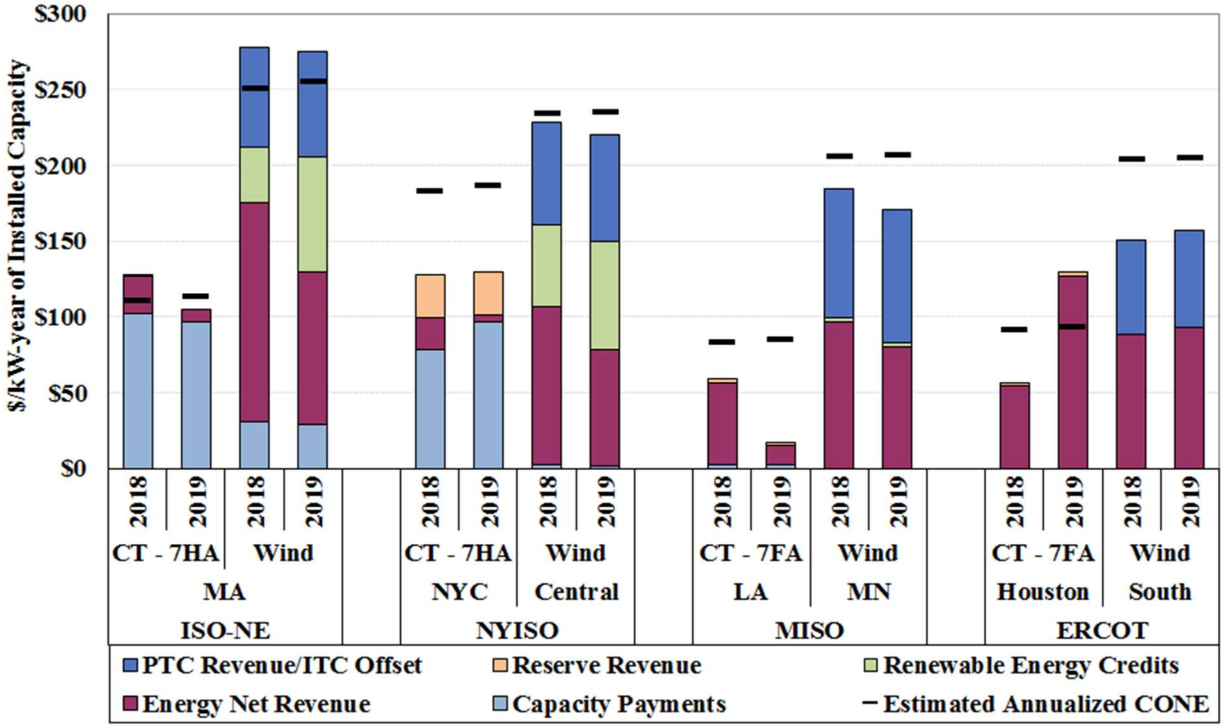
- Incentives for new generation investment in ISO-NE compared with other markets (subsection A).
- How wholesale markets complement incentives from state policies (subsection B), and
- Outlook for existing generators and implications for entry of sponsored policy resources under the Competitive Auctions with Sponsored Policy Resources ("CASPR") mechanism (subsection C).

A. Cross-Market Comparison of Net Revenues

This section compares the incentives for new investment in ISO-New England to three other markets by measuring the net revenue a new generating unit would have earned (from the wholesale market and from applicable state and federal incentives) over the past two years. Figure 8 shows estimated net revenues for a new combustion turbine and an onshore wind facility broken into the following categories: (a) energy net revenues based on spot prices, (b) capacity payments based on auction clearing prices including pay-for-performance incentives, (c) operating reserve net revenues, (d) federal production tax credits, and (e) state renewable energy credits based on the applicable program. For comparison, the figures also show the annual net revenue that would be needed for these new investments to be profitable (i.e., the "Cost of New Entry" or CONE).

Combustion Turbine ("CT"). Figure 8 shows that the net revenues provided by the ISO-NE markets for a new CT declined from 2018 to 2019 because of milder summer and winter load conditions and lower fuel prices. Capacity revenues were relatively high and accounted for the vast majority of net revenues in both years because of the tight capacity margins in the forward capacity auctions held in 2015 and 2016. Since most of the net revenue for a new CT derives from the capacity market, the decline in net energy revenues was small relative to the annualized CONE. Net revenues were comparable to the annualized CONE of a hypothetical CT in both years. Accordingly, new fossil-fueled generators entered the New England market in these years.

Figure 8: Net Revenues Produced in ISO-NE and Other RTO Markets
2018 – 2019



The NYISO and MISO markets also exhibited lower energy net revenues in 2019 because of lower gas prices and load conditions, but these reductions were generally small relative to the CONE in these markets. In contrast, ERCOT experienced several hours of shortage pricing at $9,000/MWh in the summer of 2019 because of low planning reserve margins and hot summer conditions. Consequently, the net revenues for the hypothetical CT based on spot prices increased dramatically and exceeded the CONE for the unit in ERCOT. Overall, the CTs in ISO-NE and ERCOT appear most profitable because those areas had slim capacity margins in 2018 and 2019. In contrast, New York City and Louisiana exhibited sizeable capacity surpluses in these years, which led to net revenues that were significantly lower than CONE.

Wind Resources. The net revenues of an onshore wind unit in New England were comparable to its CONE in 2018 and 2019. Although large components of net revenue were from state and federal subsidies, the majority of net revenues were from energy and capacity. This illustrates that even developers of subsidized resources must be careful to develop projects at locations where they are less likely to be curtailed or adversely affected by congestion. This helps guide investment to more efficient locations.

The market for Class I RECs in New England has continued to tighten considerably since mid-2019 because of: (i) increases in state RPS requirements (which increases the demand), and (ii) delays in the anticipated completion of offshore wind projects (which reduces the supply). State solicitations for specific resource types, such as offshore wind and solar, could potentially increase the supply of Class I RECs and moderate prices in the future.[21]

Unlike the wind units in most of MISO and ERCOT, the renewable units in New England and New York receive substantial revenues from the states' REC programs. Although the resource potential in MISO and ERCOT is better than in New England and New York, several parts of MISO and ERCOT often have more wind capability than can be delivered to load centers. Consequently, the locational prices during hours of high wind generation are likely to be considerably lower, thereby depressing the overall revenues for new and existing wind units in MISO and ERCOT.

The analysis for the wind turbine in ERCOT illustrates how net revenues fall when intermittent renewable generators reach high levels of penetration. In 2019, the wind turbine in ERCOT did not experience the dramatic increase in net revenue that was experienced by the combustion turbine. This is because in markets with high penetration of a particular renewable technology, shortage pricing events are more likely to occur when intermittent generation is lower than average. However, the controllable resources that can balance the wind see higher revenues.

B. Compatibility of Wholesale Markets with State Policies

The New England states have established ambitious clean energy targets in recent years.[22] These targets will require vast amounts of new intermittent renewable generation from solar and wind resources. In addition, large amounts of flexible resources and price-responsive demand will be needed to balance variations in intermittent renewable generation and maintain reliability. Some have begun to question the value of competitive wholesale markets given the quantity of investment anticipated from state policy initiatives.[23] However, given the high levels of

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21 See:
1. https://poweradvisoryllc.com/new-england-class-i-rec-market-update/
2. https://data.bloomberglp.com/professional/sites/24/BNEF-BCSE-2020-Sustainable-Energy-in-Amercia-Factbook_FINAL.pdf.
3. https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/northeast-class-i-renewable-energy-credit-prices-spike-more-than-13-58723442.

22 RPS and CES requirements in New England states include 44 percent by 2030 (CT), 38.5 percent by 2035 (RI), 41.1 percent by 2030 (MA), 75 percent by 2032 (VT), 25.2 percent by 2025 (NH), and 84 percent by 2030 (ME). In addition, several states have adopted resource-specific mandates or carveouts including for offshore wind, solar, energy storage and other resources.

23 For instance, as part of its proceeding to develop the 2018 Integrated Resources Plan, Connecticut's Department of Energy and Environmental Protection solicited comments on two questions:

1. What is the long-run compatibility of deregulation of Connecticut's electric energy utilities and associated market rules, administered by ISO New England, Inc. and regulated by the Federal Energy Regulatory Commission, with Connecticut's public policies and goals?

generation investment that are anticipated in the coming years, it has become more important than ever to provide efficient investment incentives to developers of intermittent generation and battery storage.

Wholesale markets are highly effective in guiding investment towards projects that provide value to a system with high penetration of intermittent resources. The market provides critical incentives for two categories of investors:

- *Developers of new renewable generation* – These firms have key choices regarding what technologies to use and where to locate specific projects. Wholesale markets reward resources that generate at times that are most valuable to end users, while avoiding transmission bottlenecks. To the extent that some developers expect to receive more in wholesale market revenues, such developers are more likely to win state solicitations, thereby lowering REC prices.
- *Developers of flexible resources* – Increased flexibility will be needed to integrate high levels of intermittent renewable generation, particularly during times of rapid changes in generation. Wholesale markets provide real-time price signals that differentiate the value of resources based on their flexibility and location, thereby delivering the highest revenues to developers of resources that are most effective in complementing renewable resources.

Therefore, state policy makers can leverage the power of markets to achieve their clean energy objectives more quickly and cost-effectively. Conversely, state objectives will be difficult to achieve if market participants have economic incentives that are at odds with the policy objectives. In the following analysis, we evaluate the long-term incentives for various flexible and renewable resources to illustrate how technology, flexibility, and location play a key role in determining whether a particular project will be profitable to a developer.

Figure 9 shows the estimated after-tax Internal Rate of Return (“IRR”) of investments in several types of new generation based on:

(a) the average net revenues from 2020/21 to 2023/24 that we estimated using forward power and gas prices, and

(b) the projected capital and operating costs for units that will be commence operations in 2024.[24,25]

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2. Are there alternative market designs that would better-align with Connecticut’s public policies and goals? If yes, what are the strengths and weaknesses of each alternative?

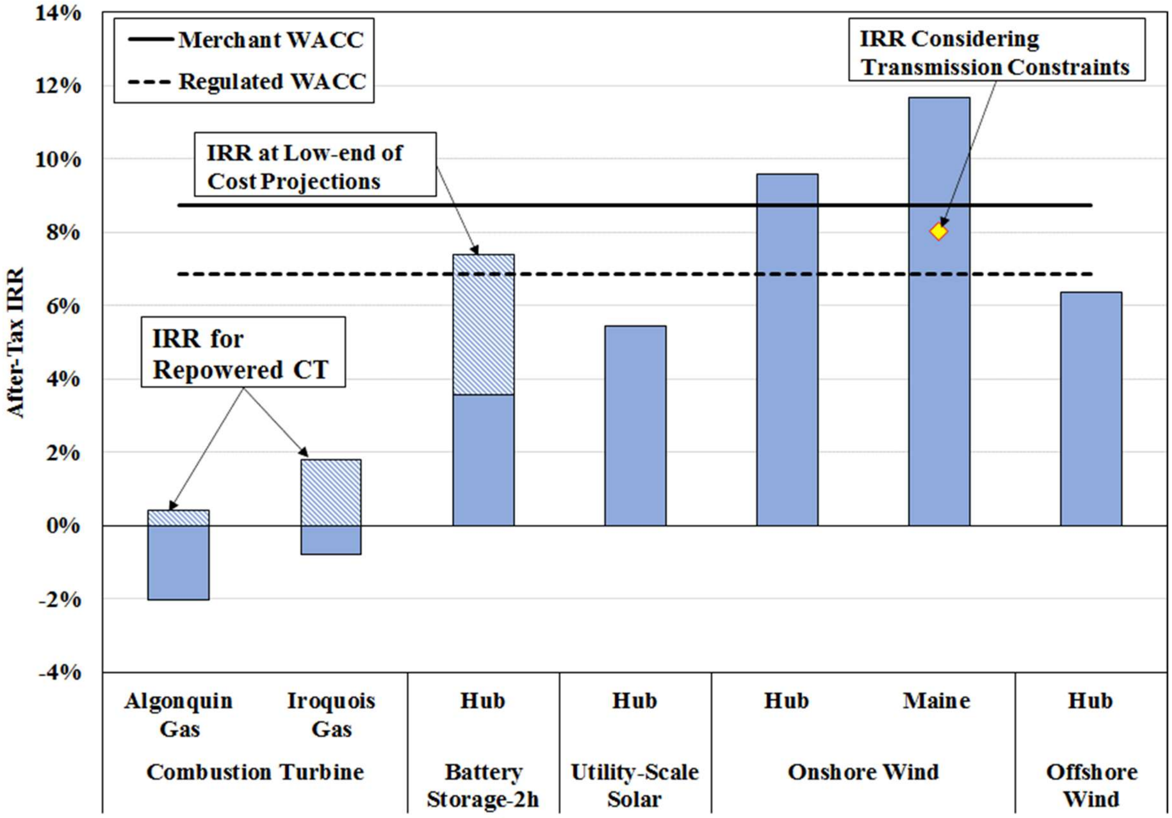
See January 8, 2020 *Notice of Technical Meeting and Opportunity for Public Comment,* available at http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/da847543db14d52a852584e9005b2f15/$FILE/FINAL%20Notice%20IRP%20Technical%20Meeting-Markets%20and%20Deregulation.pdf.

24 Net revenue is the total revenue that a generator would earn less its variable production costs. Investors seek to earn sufficient net revenue to recover the cost of their capital investments in generating units.

25 See Appendix subsections B, C, and D.

The calculation of the IRR includes energy and ancillary services revenues, capacity market revenues (including PFP-related payments), and applicable incentives including renewable energy credits, and the Investment or Production Tax Credits. The figure compares the IRR for each project with the after-tax WACC for: (a) a merchant entrant using data from the latest CONE and ORTP study, and (b) a regulated entity calculated from recent utility rate cases.[26] A project with a weighted average cost of capital below its estimated IRR would have a positive net present value and, thus, be profitable. For each technology and location, the solid bar shows the IRR based on the zonal prices, except for the Maine onshore wind unit, whose revenues were estimated based on nodal prices. For the CTs and battery storage, the light blue bar shows the IRR under a lower-cost scenario. For onshore wind, the diamond shows the reduced IRR in a case where congestion prevents the unit from selling capacity and leads to lower capacity factors.

Figure 9: After-Tax IRR of New Resources
Based on 2020/21 – 2023/24 Forward Prices



Our analysis of the investment in new resources indicates that there are significant differences in the IRR by technology and location. Of the generic renewable units studied, investment in onshore wind appears to have the highest IRR based on forward prices and estimated future costs, although renewable entry may lead to lower REC prices in the future and reduce the IRR.

26 The regulated WACC shown is calculated as an average of cost of capital values approved in recent Massachusetts rate cases for Eversource Energy and National Grid in 2017 and 2019, respectively.

A wind unit in Maine appears to be more profitable than one at the Hub. However, the Maine unit is actually less profitable when we consider the transmission upgrade costs that would be required to sell capacity and the effects of curtailments. Our analysis shows that onshore wind appears more profitable than utility-scale solar and offshore wind generation.

For the flexible technologies studied, investment in battery storage resources appear to have the highest IRR. In contrast, investment in CTs in this time frame indicates low projected returns relative to a normal rate of return (i.e., a merchant WACC).[27] Even the IRR for battery storage appears relatively low compared to the estimated merchant WACC, but this is not surprising given the substantial capacity surplus in the years analyzed. Battery storage costs are expected to fall significantly over the next five years, so the incentives for new investment in battery storage may continue to improve.[28] The returns for flexible resources are expected to increase if the growth of intermittent renewable resources increases the frequency of operating reserve shortages and overall price volatility.

The LMPs across New England exhibit relatively little congestion, but our analysis suggests that some locations enjoy modest advantages. For example, conventional resources in Connecticut with access to Iroquois gas pipeline provide considerably better returns relative to other locations.[29]

Although state and federal incentives account for large components of the net revenues for renewables, this analysis demonstrates how the ISO-NE markets are designed to provide price signals that differentiate among projects by rewarding technologies that are most valuable to the system. Favoring investments in a particular technology tends to crowd-out investment in the alternatives, and the wholesale markets allows for efficiently modulating the value of specific technologies as the resource mix evolves over time. Furthermore, given the projected cost declines for batteries, the markets are also capable of incenting entry of flexible battery storage installations that could enable greater integration of clean energy resources. Hence, wholesale markets work in a manner that is highly complementary to the states' clean energy policies.

Perceiving a potential conflict between the market rules and their policies, a number of states across the country have intiaited discussions to explore alternatives to elements of centrally organized wholesale power markets. However, as discussed above, markets are compatible with

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27 The low IRR for the CT is noteworthy given that the analysis in Subsection A suggests that a unit entering in 2018 and 2019 would have been relatively profitable because of much higher capacity prices.

28 For instance, 2-hour battery resources could be economic at capacity prices in the $5.00/ kW-mo to $5.50/ kW-mo range if optimistic cost declines are realized. There is considerable uncertainty in the costs of battery installations over the next few years, and the actual costs will depend on the evolution of battery chemistries and cell/pack design, manufacturing capacities, costs of underlying metals, etc.

29 The IRR calculations in this section are based on average futures prices from January through April 2020. However, future prices have declined notably ($2 to $4, per MWh depending on the year) from January and February to recent weeks as a result of the Covid-19 pandemic.

state policy and can help achieve states' goals in an efficient manner. In addition, forthcoming market design initiatives (e.g., cooptimized day-ahead operating reserve markets) are likely to enhance the alignment of the prices with the value of generation. These initiatives can aid an efficient transition to a low carbon grid, particulary in conjunction with increased carbon pricing.

New England is well positioned to balance state policy and market competitiveness concerns with the CASPR mechanism, which is already in place. CASPR was approved by the FERC and developed after extensive discussions among the stakeholders. We discuss the ability of Sponsored Policy Resources ("SPRs") to obtain a CSO in the upcoming FCAs under the CASPR mechanism in the next subsection.

Some parties have advocated for long-term contracts as an alternative to centrally-coordinated capacity markets for satisfying resource adequacy needs. However, such a transition would be extremely costly and inefficient as it will not coordinate efficient investment in new resources or retirement of existing resources. It will also: not procure resources in the most valuable technologies and/or locations, place excessive investment risk on end users, and be detrimental to innovation overall. Moving away from competitive markets would ultimately render it extremely difficult for the states to achieve their ambitious environmental policy goals while maintaining reliability. Indeed, California, which relies on a state-directed long-term contracting model for resource adequacy, is going through a process to overhaul its resource adequacy mechanism after recognizing that "Given the passage of time and the rapid changes occurring in California's energy markets, it may be worthwhile to re-examine the basic structure and processes of the Commission's RA program."[30]

C. Incentives for Existing Generators and Implications for Sponsored Policy Resources

The ISO designed the CASPR mechanism to enable entry of SPRs without being subject to the MOPR, while maintaining competitive capacity market outcomes. Under CASPR, existing resources that obtained a CSO and are willing to retire can transfer their CSOs to SPRs during the course of the Substitution Auction ("SA") that is conducted immediately after the primary auction of each FCA.

The ISO conducted SAs after FCA-13 and FCA-14, and it cleared 54 MW and 0 MW of supply from SPRs, respectively. The ISO's recent publication indicates that the amount of supply clearing the SA after FCA-15 is also likely to low, as a maximum of only 199 MW of retiring resources are likely to place demand bids.[31] However, the states have aggressive clean energy

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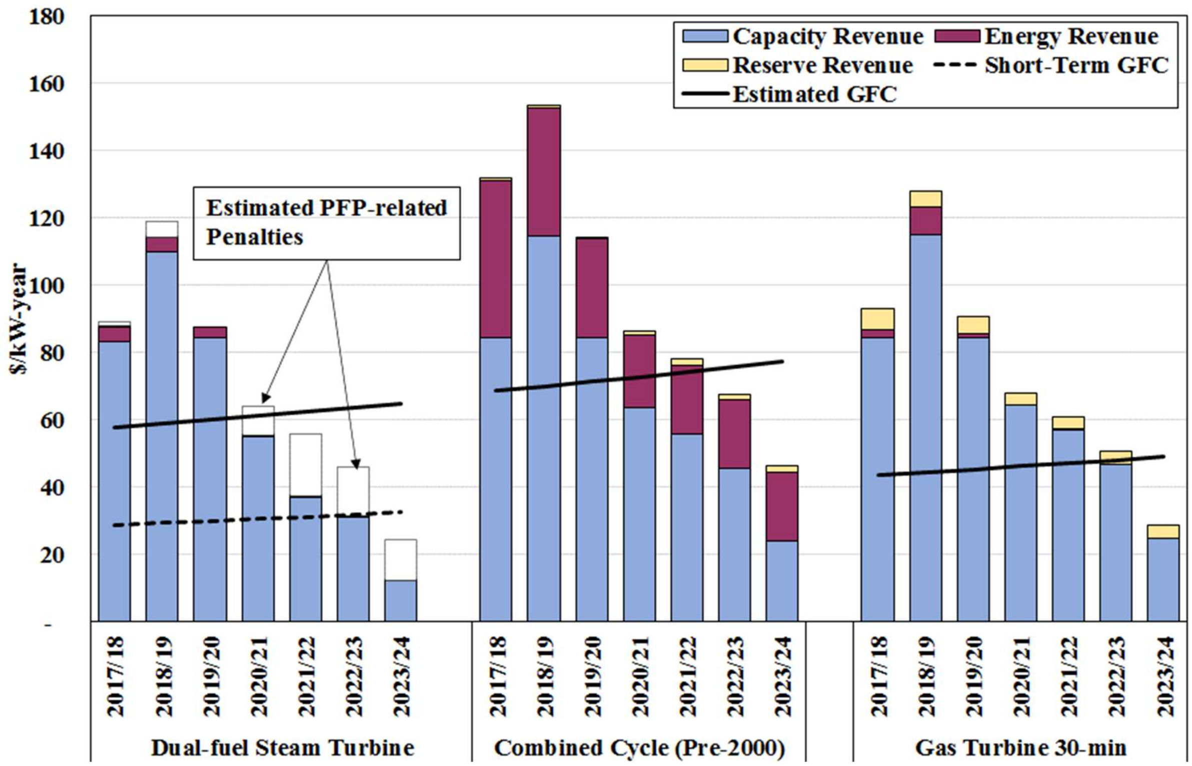
30 *Order Instituting Rulemaking to Oversee the Resource* Adequacy *Program*, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2019 and 2020 Compliance Years, dated September 28, 2017, California PUC Rulemaking 17-09-020, page 2.

31 See https://www.iso-ne.com/static-assets/documents/2019/10/substitution-auction-bid-and-offer-summary.pdf. Note that although nearly 2,350 MW of capacity has expressed interest in obtaining CSOs in the SA, the actual

targets, which would result in large amounts of SPRs being precluded from the obtaining a CSO if the demand continues to be low in future FCAs.[32]

The demand in SAs will be driven by the amount of capacity that seeks to exit the market permanently. Therefore, we analyze the profitability of existing units and discuss the potential for CASPR to enable new entry of SPRs in future FCAs. Figure 10 shows the net revenues and estimated going-forward costs ("GFCs") for three existing technologies from 2017/18 to 2023/24. These existing generators are evaluated because they are most likely to retire in the coming years. Following the 2023/24 Capability Year, ISO-NE has over 4.5 GW of dual-fuel steam turbines, 3 GW of older peakers, and 4 GW of combined-cycles installed before 2000.

Figure 10: Net Revenues and Going-Forward Costs of Existing Units
2017/18 – 2023/24



The net revenues shown in Figure 10 include revenues from the sale of energy, ancillary services and capacity. The empty bars show the estimated impact on capacity revenues from below average performance during reserve shortage events. The "Estimated GFC" for a generic unit includes the average cost of maintaining an existing generator in reliable condition. However, a firm may be able to avoid a considerable portion of the cost by deferring maintenance and other capital expenditures in the short-term. Therefore, the figure also shows a "Short-Term GFC" for

capacity that was entered as supply in the SA was far smaller (292 MW in FCA-14). See ISO-NE Interal Market Monitor's *2019 Annual Markets Report, Section 6.3.3*.

32 See ISO-NE's 2020 Regional Energy Outlook.

steam units, which reflects non-deferrable short-term costs, primarily fixed O&M and property taxes.[33,34]

As with new units, the net revenues of existing units relative to their costs vary significantly by technology. Based on recent forward pricing for energy and capacity, the net revenues of all three types of generic units that we studied are likely to decline significantly in the future. The estimated impact of reserve shortages on the capacity revenues of the steam turbine are relatively large. Steam turbine units are generally inefficient and inflexible with long lead times for starting-up. Consequently, the forthcoming increase in the PPR is likely to increase the risk of substantial PFP-related penalties for these units. Indeed, the capacity-weighted average availability of steam turbines was close to 12 percent during the September 3, 2018 shortage event, which resulted in a large reduction in capacity revenue to this group. Consequently, we estimate that in 2023/24, a steam turbine's expected revenues would equal its:

- Short-term GFC at a capacity clearing price of $3.7/kW-month, since its capacity revenues would be reduced by an expected 27 percent during PFP events
- Long-term GFC at a capacity clearing price of $6.5/kW-month, since its capacity revenues would be reduced by an expected 16 percent during PFP events; and

Given the outlook for steam turbine capacity in New England, it is likely that some will be willing to retire in the coming years and, thus, most likely to constitute demand in future Substitution Auctions. However, there is considerable uncertainty regarding the actual price level at which an existing unit owner would choose to retire. The decision to retire and the actual GFCs depend on a range of factors including the owner's expectations of future market prices, expectation of retirements from similarly situated units, long-term contracts, the age of the unit, and the level of incremental capital and maintenance expenditure required to continue operations. In particular, the retirement of Mystic 8 and 9 units (1.4 GW) may have led asset owners to risk negative cash flows for one or two years in anticipation of higher capacity prices in FCA-15.[35]

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33 Typical GFCs were estimated from a review of public studies and historical FCA delist bid submissions. Short-term going-forward costs primarily include Fixed O&M, and are consistent with average values for steam turbine plants several decades in age surveyed by Burns & McDonnell in "Life Extension & Condition Assessment for Rio Grande Unit 7", July, 2018, as well as property taxes in New England states. Long-term GFCs are consistent with estimates performed by London Energy Economics for the New England States Committee on Electricity (NESCOE) Renewable and Clean Energy Scenario Analysis and Mechanisms 2.0 Study, Phase I, Scenario Analysis Report, 2017. Public estimates and historical submissions indicate a range of plant-specific GFCs in practice.

34 The GFCs shown in the figure do not include any Risk Premium that the IMM allows for inclusion in a unit's de-list bid. The Risk Premium could be substantial, and is intended to capture risks that are quantified and analytically supported. Furthermore, a number of unit-specific factors could result in GFCs that differ significantly from the estimated GFCs.

35 The potential increase in prices from the retirement of Mystic 8 and 9 units depends on the capacity zone configuraton for FCA-15.

However, the potential upside to capacity prices from the retirement of Mystic 8 and 9 units is limited by at least two factors: (a) the potential entry of unsubisidized battery storage resources, and (b) a potential repowering that would replace the capacity retiring at the existing Mystic site.

- Based on our analysis in Subsection B, it is plausible for battery storage resources to be economic at capacity prices in the $5.00 to $6.50 per kW-month range. If future FCAs continue to see significant interest from these resources, the generic steam turbine unit may be unprofitable to operate much longer, especially after accounting for the risk of PFP-related penalties.[36]
- Exelon recently indicated the possibility of selling up to 1.6 GW of capacity from the Mystic site in an upcoming FCA. The capacity prices (and the economics of the steam units) in such a situation would depend significantly on the Offer Floor Price for the new capacity, which could be considerably lower than the Net CONE, depending on the extent to which the new capacity would utilize existing facilities.

Overall, the economics of the generic steam units that we studied appear to be challenged with limited upside despite the imminent retirement of Mystic units 8 and 9 in FCA-15. Accordingly, there is likely to be a significant potential demand under the CASPR mechanism in future auctions. However, the timing of unit retirements may be difficult to determine. This is because asset operators have considerable latitude to defer capital and operational expenses, and they may exit the market only in case of an unexpected event and/or when they deem additional expenses to be absolutely necessary for continued operation. In addition, to the extent SPRs with a high degree of availability or flexibility enter the market, they could reduce the probability of shortage events, and consequently, alleviate the financial pressure on steam turbines.

D. Conclusions

The ISO-NE markets provide price signals that motivate firms to invest in new resources and maintain or retire existing generating units. In this section, we evaluated the investment incentives for various renewable, flexible and existing resources in ISO-NE. We compared the incentives for investment in a combustion turbine and wind resources across several wholesale markets. We also discussed the compatibility of wholesale markets with states' clean energy policies, and the potential for the CASPR mechanism to enable entry of SPRs in future FCAs.

Cross-Market Comparison of Net Revenues

In 2019, the CTs in ISO-NE and ERCOT appear most profitable and the revenues likely exceeded or were similar to the CONE because those areas had slim capacity margins. The slim margins resulted in higher capacity prices in ISO-NE and a higher number of shortage pricing

36 The capacity price requirements for battery resources were estimated based on projected costs and forward prices. Therefore, to the extent that the costs do not decline with expectations, the required capacity prices would be higher.

hours in ERCOT. In contrast, New York City and Louisiana exhibited sizeable capacity surpluses in these years, which led to net revenues that were significantly lower than CONE.

The net revenues of an onshore wind unit in New England were comparable to its CONE in 2018 and 2019. Although large components of net revenue were from state and federal subsidies, the majority of net revenues were from energy and capacity, illustrating the role of markets in guiding investment to more efficient locations. Although the resource potential in MISO and ERCOT is higher than in New England, wind units in most of MISO and ERCOT did not appear to be economic likely because of two reasons:

- Unlike units in New England and New York, the renewable units in MISO and ERCOT do not receive substantial revenues from the states' REC programs.
- Due to high penetration levels, the prices during hours of high wind generation are likely to be considerably lower, thereby depressing the overall revenues for wind in MISO and ERCOT.

Notably, the wind turbine in ERCOT did not experience the dramatic increase in net revenue that was experienced by the combustion turbine in 2019. This is because in markets with high penetration of a particular renewable technology, shortage pricing events are more likely to occur when intermittent generation is lower than average.

Compatibility of Wholesale Markets with State Policies

The New England states have ambitious clean energy targets which will require vast amounts of new intermittent renewable generation and large amounts of flexible resources and price-responsive demand will be needed to balance variations in intermittent renewable generation. Given the high levels of generation investment that are anticipated to occur in the coming years, it has become more important than ever to provide efficient investment incentives to developers of intermittent generation and battery storage. Wholesale markets are highly effective in guiding investment towards projects that provide value to a system, and state policy makers can leverage the power of markets to achieve their clean energy objectives more quickly and cost-effectively.

Our analysis of investment in several new renewable and flexible resources indicates that there are significant differences in their profitabilty by technology and location. Of the renewable technologies we analyzed, onshore wind appears more profitable than utility-scale solar and offshore wind generation. For the flexible technologies studied, investment in battery storage resources appear to be the most profitable, while investment in CTs is likely produce low returns based on current forward prices. This analysis demonstrates how the ISO-NE markets are designed to provide price signals reward technologies that are most valuable as the system transitions to one with large quantities of renewable resources.

Perceiving a potential conflict between the market rules and their policies, a number of states across the country have intiaited discussions to explore alternatives to elements of centrally organized wholesale power markets. However, wholesale markets work in a manner that is highly complementary to the states' clean energy policies. A number of forthcoming market design initiatives are likely to enhance the alignment of the prices with the value of generation, and can further aid an efficient transition to a low carbon grid.

New England is well-positioned to balance state policy and market competitiveness concerns with a FERC-approved CASPR mechanism already in place. Furthermore, the CASPR mechanism is superior to long-term contracts as a means to satisfy resource adequacy needs. Moving away from centrally-coordinated capacity markets to a long-term contracts model would be extremely costly and inefficient. A long-term contracting model will not coordinate efficient investment in new resources or retirement of existing resources, and render it extremely difficult for the states to achieve their ambitious environmental policy goals. It will also: not procure resources in the most valuable technologies and/or locations, place excessive investment risk on end users, and be detrimental to innovation overall.

Potential for CASPR to Enable Entry of Sponsored Policy Resources

The ISO designed the CASPR mechanism to enable entry of SPRs without being subject to the MOPR, while maintaining competitive capacity market outcomes. However, the ISO cleared 54 MW and 0 MW of supply from SPRs in the two auction it has conducted so far. The potential for CASPR to enable new entry of SPRs in the future auctions is determined by the economics of existing units.

Our analysis indicates that of the existing technologies we evaluated, steam turbine units are the most challenged economically largely because of lower capacity prices in the upcoming Capacity Commitment Periods and higher risk of PFP-related penalties. Hence, some steam turbine units may contemplate retirement. However, there is considerable uncertainty regarding the actual price level at which an existing unit owner would choose to retire because of a number of factors. In particular, the imminent retirement of Mystic 8 and 9 units (1.4 GW) may have led asset owners to risk negative cash flows for one or two years in anticipation of higher capacity prices in FCA-15. However, the potential upside to capacity prices from the retirement of Mystic 8 and 9 units is limited by: (a) the potential entry of unsubisidized battery storage resources, and (b) a potential repowering that would replace the capacity retiring at the existing Mystic site.

Overall, our analysis suggests that there is likely to be a significant potential demand to meet the supply of SPRs in future auctions. However, the timing of retirements may be difficult to determine as owners have considerable latitude in deferring costs. Furthermore, to the extent units with a high degree of availability or flexibility enter the market, the financial pressure on steam turbines could be alleviated due to reduced frequency of shortage events. This is a key factors because the frequency of PFP events substantially affects the economics of the steam turbines.

V. Evaluation of the Pay-for-Performance Framework

The PFP rules were put in place to enhance incentives for suppliers to perform when they are needed the most. As part of the PFP rules, resources that provide more energy and/or operating reserves than the average capacity provider during a reserve shortage event are paid a Performance Payment Rate ("PPR"), while capacity suppliers that produce less than average are penalized according to the PPR. The Pay-for-Performance ("PFP") rules became effective on June 1, 2018.

The first PFP event in New England occurred from 15:40 to 18:15 on September 3, 2018. During the event, the shortage of 30-minute reserves ranged from 200 MW to 880 MW. The shortage resulted from a combination of factors that included unexpectedly high load (actual load exceeded forecast by ~2.5 GW), the sudden loss of the Mystic 8 and 9 units due to a gas pressure issue (~1.4 GW), and other forced outages and deratings. During the event, the LMP at the Hub approached nearly $2,700/MWh in some five-minute intervals due to the shortage of 10-minute and 30-minute reserves.[37] In addition, resources that supplied energy or operating reserves were compensated (or charged) based on the PPR of $2,000/MWh. Therefore, a resource that produced energy or operating reserves during this event would have been compensated at a marginal rate of over $4,700/MWh in some intervals.

While the PFP rules have undoubtedly strengthened the incentives for capacity resources to be available and perform reliably during a shortage of operating reserves, stronger incentives are not always efficient. One key concern with the PFP rules is that there is a single PPR that applies to all 10-minute and 30-minute reserve shortages, regardless of severity. When the ISO originally filed the PFP rules, it acknowledged that the PPR should undergo refinement over time. This section of the report examines the implications of having a single PPR for all reserve shortages and how this may adversely influence investment incentives.

In Subsection A, we compare the compensation suppliers received during the first PFP event to the expected value of load that was at risk of not being served. In Subsection B, we evaluate the incentives for energy storage resources under the current PFP and FCM rules, and we identify a misalignment between their compensation and their value to the system. In Subsection C, we discuss the misalignment between large resources' compensation and their value to the system. The final subsection provides a summary of our conclusions and recommendations.

37 The Reserve Constraint Penalty Factor ("RCPF") is the value that the real-time market model places on satisfying a particular reserve requirement. The RCPF for the 30-minute reserve requirement is $1,000/MWh, and the RCPF for the 10-minute reserve requirement is $1,500/MWh, so a shortage of both types of reserves results in clearing prices of $1,000/MWh for 30-minute reserves and $2,500/MWh for 10-minute reserves, since 1 MW of 10-minute reserves contributes to meeting both requirements. LMP rose above $2,500/MWh, reflecting that one additional MW of energy would allow the model to back down an expensive generator to provide one additional MW of 10-minute reserves.

A. Evaluation of Pay-for-Performance Pricing

Efficient prices during reserve shortages play a key role in establishing economic signals to guide investment and retirement decisions in the long-run and facilitate efficient commitments and reliable performance in the short-run. In this subsection, we evaluate the efficiency of: (a) the shortage prices during the September 3, 2018 PFP event, (b) the prices that would have occurred if the reserve shortages had been deeper during the event, and (c) the prices that would have occurred at various reserve shortage levels if the generation mix contained significant levels of supply from intermittent renewables.

During shortages, efficient prices should be set consistent with several criteria. Specifically, prices should:

- Reflect the marginal reliability value of reserves given the shortage level;
- Depend on the risk of potential supply contingencies, including multiple simultaneous contingencies; and
- Rise gradually as the reserve shortage increases and have no artificial discontinuities that can lead to excessively volatile outcomes.

The marginal reliability value of reserves is equal to the expected value of the load that will not be served if the available reserves are reduced by 1 MW. The expected value of lost load ("EVOLL") during a reserve shortage event can be estimated as the product of: (a) value of lost load ("VOLL"), and (b) the probability of losing load. We estimated (a) and (b) during the September 3, 2018 PFP event for comparison with the actual prices in the following manner:

- We assume a VOLL of $30k per MWh, which is on the high end of VOLL values that have been estimated;[38] and

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[38] Estimates of the VOLL vary widely based on a range of demand-side factors that include the customer class being served, duration of the load shedding event, season/ timing of the event and geographical location of customers. A meta-analysis of reliability studies by LBNL and DOE estimated that in a one-hour power interruption, a small C&I customer (who may not have installed power back-up systems) could incur a cost per unserved kWh that is nearly 90 times the cost incurred by a residential customer. (See 2015 report on study tiltled *Estimated Value of Service Reliability for Electric Utility Customers in the United States*.) This study also estimated the cost of interruption for residential customers on a summer morning/ night could be nearly 4 times the cost of interruption on a non-summer evening. VOLL is also known to rise as the length of the outage increases, so a 16-hour long outage can cost an average large C&I customer nearly 22 times what a momentary outage would cost. Hence, VOLL is not a single value and varies considerably.

On the other hand, the VOLL that is implied by capacity market payments (estimated to be over $200,000 per MWh in several studies) is significantly higher than the VOLL across almost the studies (and across all key parameters discussed above). This is because capacity markets set capacity demand curves based on the estimated revenue necessary to satisfy certain reliability standards (rather than an evaluation of demand-side factors).

The ISO's planned PPR of $5,455 per MWh is derived based on the following two principles: (a) a new entrant's expected FCM revenue should cover its Net CONE and any risk premium it requires to accept a CSO, and (b) a new or existing capacity supplier's FCM revenue should be zero if it expects to not perform during

- Given the resource mix of the reserve and energy output during the event, we estimated the probability of losing load using a Monte Carlo simulation. This simulation incorporates the risk of concurrent generator forced outages and renewable generation forecast error during the PFP event to estimate the probability of 10-minute reserves falling to a level below 700 MW.[39]

As the magnitude of the operating reserve shortage increases, the EVOLL increases because the probability of losing load increases. It is efficient for the prices to increase in accordance with the EVOLL because this will provide appropriate incentives for both suppliers and demand to take actions that are consistent with the reliability value of the actions. Therefore, we estimated how the implied EVOLL curves would change at various reserve shortage levels (using Monte Carlo simulation results) and compared it to the compensation that suppliers would receive (under the current rules) at that shortage level.

Furthermore, the penetration of intermittent renewables could have a significant bearing on the net load forecast error, which would impact the the EVOLL at a given reserve level. Accordingly, we analyzed three scenarios, each based on a different resource mix, to illustrate the impact of renewable penetration on the prices as determined by EVOLL curves:

- *Base* – In this scenario, we estimated the EVOLL curve based on a resource mix that corresponded to the average of observed reserve and energy output by resource during the September 3, 2018 PFP event.
- *Distributed Renewables* – In this scenario, we adjusted the *Base* resource mix by incorporating an additional supply of 2000 MW of energy from distributed or small utility-scale renewable resources. We also modeled the firm entry and exit of fossil-fired generation as determined by the recent FCA outcomes.
- *Large Renewables* - In this scenario, we adjusted the *Base* resource mix by incorporating an additional energy supply of 2000 MW of energy from five large utility-scale renewable installations. We also modeled the firm entry and exit of fossil-fired generation as determined by the recent FCA outcomes.

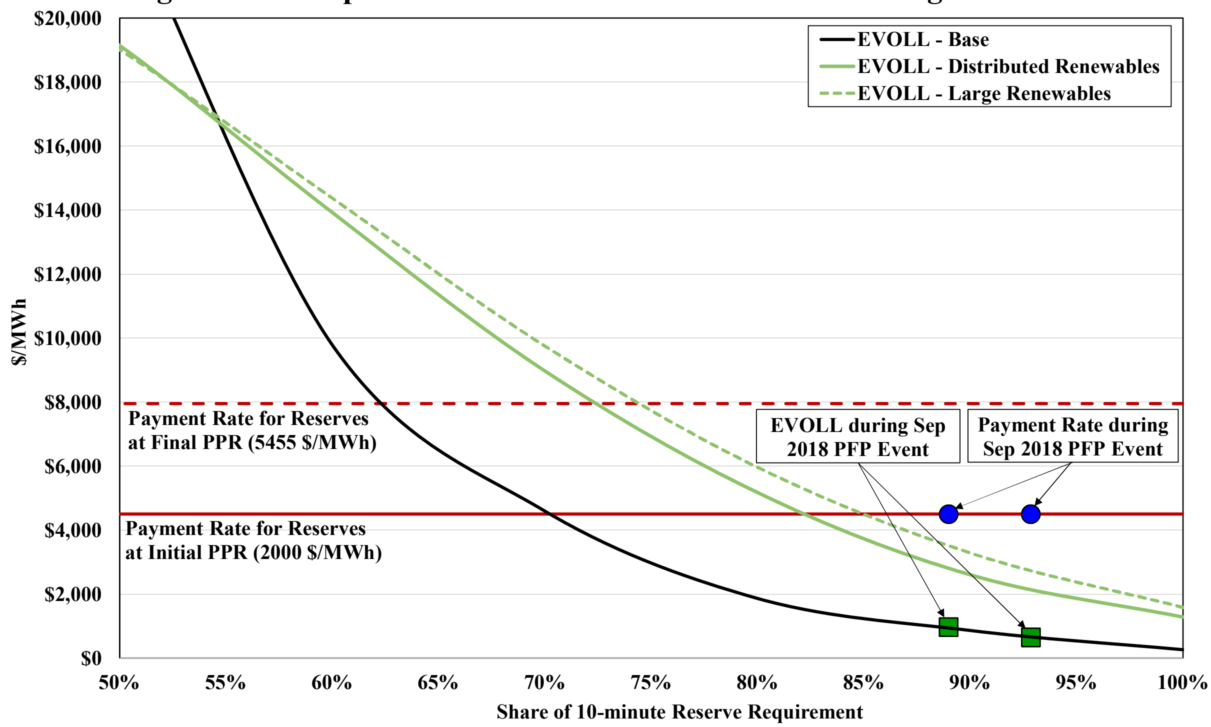
Figure 11 shows how the EVOLL would vary based on the amount of 10-minute reserves that are available to the system under three different scenarios. The figure compares the EVOLL curves under the three scenarios to the current and future payment rates under the current PFP rules. The figure also shows the payment rate that resources performing during the September 3,

scarcity conditions. See ISO's September 4, 2013 memo to NEPOOL Markets Committee on *FCM Performance Incentives – Performance Payment Rate*. Hence, the ISO's PPR values are not necessarily related to the VOLL during reserve shortages.

[39] We assumed that the time between generator forced outages is a random variable that follows a Poisson process. We assumed that the mean of the probability distribution is the corresponding class-average Mean Service Time to Unplanned Outage ("MSTUOs") derived from NERC GADS data. We used the MSTUO for each generator in our simulations to derive the probability that the generator would be on an outage during a two hour look-ahead window. See the Appendix for assumptions underlying our analysis.

2018 PFP event would have received under the current rules, and using the EVOLL curve for the *Base* scenario.

Figure 11: Comparison of Reserve Prices to EVOLL during PFP Events

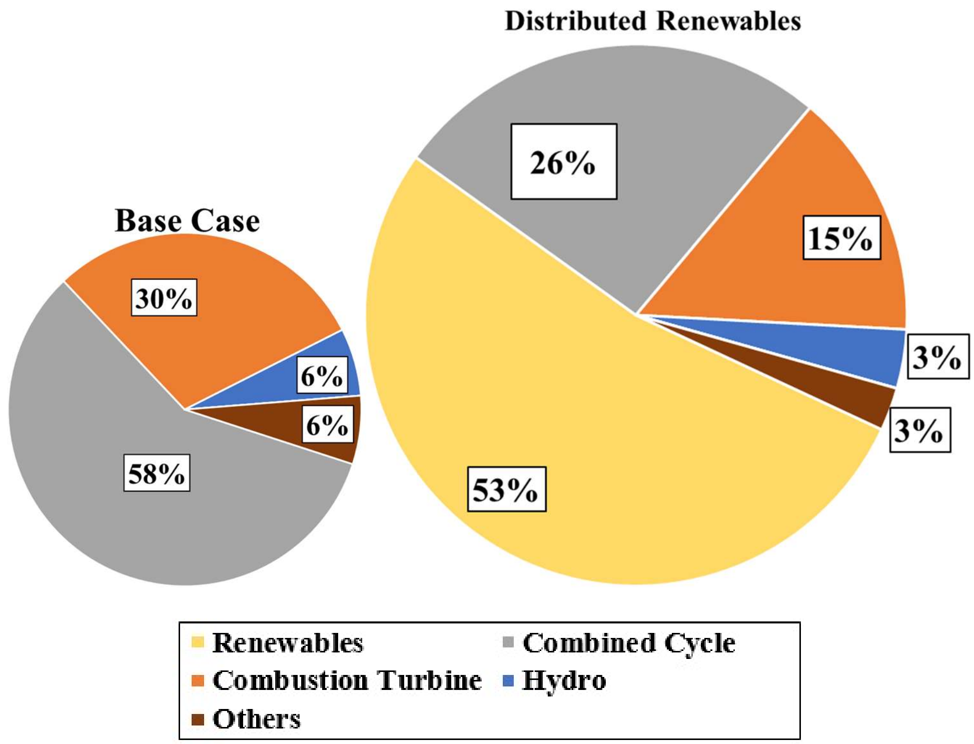


Efficiency of Prices during PFP Event - Our simulation results indicate that the highest probability of losing load during the PFP event was only 3.3 percent per hour, which translates into approximately $1,000 per MWh of operating reserves. In contrast, resources that produced energy or reserves during this interval were compensated at a rate of over $4,700 per MWh. When the PPR reaches its maximum level in 2024/25, compensation for resources performing during a PFP event could exceed $7,950 per MWh. Hence, the compensation to resources during shortages would substantially exceed the EVOLL in the vast majority of situations and would result in exaggerated shortage pricing that could motivate participants to take inefficient actions.

Shape of EVOLL Curve - The EVOLL curve has a convex shape to it which indicates that the probability of losing load increases significantly during deeper reserve shortages than during shallow reserve shortages. However, the PPR and the RCPFs are flat and do not reflect this shape. Our results indicate that the combined rate of compensation would be far higher than efficient price levels during shallow shortages and much lower during deep shortages. This could result in over-compensating flexible resources that are capable of helping resolve transient and shallow shortages, and under-compensating resources that contribute to resolving deeper and more serious shortage events.

<u>*Impact of Renewables on EVOLL*</u> - Our results also indicate that renewables have a significant impact on the probability of losing load at a given reserve level, and consequently, on the EVOLL. Figure 12 shows the average contribution of each resource type to the probability of losing load in a 600 MW shortage event under the *Base* and *Distributed Renewables* scenarios.[40] The relative size of the pie charts indicates the estimated probability of lost load under each scenario, while the slices of the pie indicate each resource type's contribution within the scenario.

Figure 12: Distribution of Outage Risk by Technology Type



The uncertainty in forecasting the output from renewable resources results in EVOLL curves that are higher than in the *Base* case for nearly all reserve shortage levels. Our results also indicate that the probability of losing load is lower under the *Distributed Renewables* scenario when compared to the *Large Renewables* scenario as the risk of large outages is higher under the latter scenario. Furthermore, incorporating renewable resources (which bring considerable forecast error) into a fossil-heavy system (where the primary risk is generator outages) tends to "smooth-out" the distribution of reserve shortages. Consequently, the EVOLL curve for the *Distributed Renewables* case is flatter and does not exhibit big increases in EVOLL for small changes in reserve levels.

40 See Appendix subsection A.

Therefore, the EVOLL curve depends on the underlying resource mix, and relying on a single value of PPR to determine prices across all scenarios and reserve shortage levels would not be efficient. As discussed in Section IV.C, PFP-related penalties are likely to have a significant impact on the retirement decisions for steam turbine resources and enable entry of SPRs. Therefore, efficient pricing during shortage events is critical for the integration of renewable resources.

Overall, modulating the PPR based on the reserve shortage level would enhance price formation during shortage events and result in more efficient short and long-run decisions from suppliers. In the following subsections, we illustrate two negative effects of not providing efficient incentives during reserve shortage events.

B. Incentives for Energy Storage Resources under Pay-for-Performance

The FCM rules allow battery storage resources to qualify to sell 100 percent of their maximum capability. Owners of energy storage units are exposed to some performance risk under the PFP framework, however, the current PFP rules do not provide sufficient discipline to energy storage resources in qualifying their capacity for the FCM. Battery storage resources are generally over-compensated for their contribution to system reliability. In this subsection, we discuss this issue further and illustrate the misalignment using simulation results.

Although a storage resource is limited in the duration over which it can provide energy, it can provide reserves for extended periods of time. Unless required to discharge and produce energy during load shedding events, its reserve capability will not be diminished during reserve shortages. Our simulations of a system with just enough capacity to satisfy a 1-day-in-ten-year standard indicate that load shedding is expected to occur in only two percent of reserve shortage hours.[41] Accordingly, the risk of PFP penalties may not be significant for storage resources relative to the potential upside in the form of higher capacity revenue.

Although the owners of storage resources may find it profitable to sell 100 percent of their capacity in the FCM, the reliability value they provide is not likely to be consistent with their compensation. This is illustrated in Figure 13, which shows a hypothetical series of five days with reserve shortages, three of which also show load shedding. Hours with load shedding or reserve shortages are identified with the letter “L” or “R”. Hours are shown as green if the resource would receive credit under the PFP rules and red if the resource would be deemed unavailable. The example is shown for a two-hour resource.

41 The actual simulations were based on the representation of the NYISO system in GE-MARS for 2017/18. While the duration of reserve shortage events and load shedding events are likely to vary from market to market, this analysis captures the essential fact that some load shedding events are longer in duration than the capacity of battery storage resources.

Figure 13: PFP Revenues and Penalties for a 2-Hour Battery During a Reserve Shortage

Hour ➡	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Day 1											R	R	R	R	R	R	R	R						
Day 2											R	R	R	R	L	R	R	R						
Day 3											R	R	R	R	L	L	L	R						
Day 4											R	R	R	L	L	L	L	R						
Day 5											R	R	R	R	R	R	R	R						

Reserve Shortage Hours

R = Reserve Shortage
L = Load Shedding

PFP Penalty
PFP Revenue

The example shows eight load shedding hours and 32 hours with just reserve shortages. On Day 1, Day 2, and Day 5, the energy storage resource is not used for its full duration of two hours, so it has sufficient charge to provide 100 percent of its capacity as energy or reserves in each hour. On Day 3, the unit runs out of charge after hour 16, making it unavailable in hours 17 and 18. On Day 4, the unit runs out of charge after hour 15, making it unavailable in hours 16 to 18.

In this example, the battery storage resource:

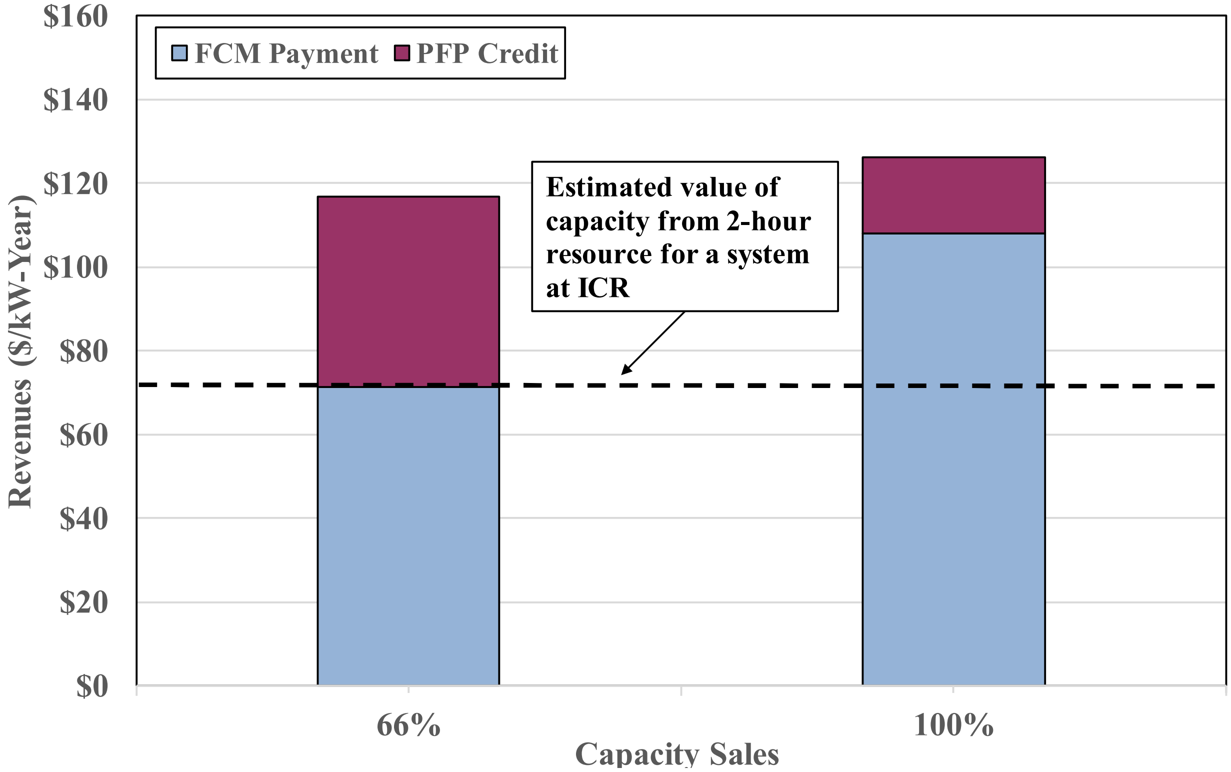
- Has a capacity value of 62.5 percent (compared to perfect availability) because it is helping reduce the magnitude of load shedding in five of eight load shedding hours.
- Will receive a PFP availability rating of 87.5 percent (of perfect availability) because it is providing energy or reserves in 35 of 40 hours with reserve shortages (including load shedding hours).

To evaluate whether there are inconsistencies between the value of battery storage resources for maintaining reliability and the compensation they receive in the capacity market, we performed Monte Carlo simulations of GE-MARS to quantify the value of battery storage resources and the compensation they would receive.[42]

Studies have found that the value of capacity from storage resources is heavily dependent on the penetration level of energy storage resources systemwide. We found that the capacity value of a 2-hour battery storage resource was 63 to 68 percent when the overall penetration of storage resources is 500 MW. In contrast, 2-hour resources were qualified to sell 100 percent of their maximum capability in FCA-13 and FCA-14. We also quantified the number of reserve shortage hours and the combined compensation from capacity revenues and PFP credits for a 2-hour resource would be expected to earn. This is shown for a CSO of 66 percent and 100 percent of its capacity. Figure 14 shows the breakdown of a 2-hour energy storage resource's revenues under these scenarios.

42 See *Alternative ELR Capacity Value Study: Methodology and Updated Results*, NYISO Installed Capacity Working Group on February 25, 2019 at https://www.nyiso.com/icapwg?meetingDate=2019-02-25.

Figure 14: Breakdown of Revenues for a 2-Hour Battery Resource
Assuming 66/100 Percent Capacity Sales



As shown in Figure 14, storage resources would find it most profitable to sell 100 percent of their capacity in the FCA. In addition, the battery storage resources would also receive more PFP credit than the average capacity supplier. Overall, this resource would receive 117 percent of the compensation of a capacity supplier with average performance.

Even if the storage resources were limited to selling 66 percent of their capacity in the FCA, the battery storage resources would receive a large PFP credit. Overall, this resource would receive 108 percent of the compensation of a capacity supplier with average performance. Although this would reduce the over-compensation to the battery storage resource, it would leave the compensation far above the estimated efficient level of 66 percent.

Hence, the 2-hour battery storage resources appear to be over-valued significantly in the capacity market for two reasons:

- Storage resources are able to sell 100 percent of their maximum capability even though resource adequacy modeling indicates 2-hour storage resources are far less valuable for preventing load shedding than the average conventional resource.
- Storage resources are likely to have high rates of availability during operating reserve shortages and comparatively lower availability during load shedding events.

A key reason why the PFP construct would over-compensate storage resources is that the PPR is the same for all reserve shortages, regardless of the probability that additional reserves would help avoid load shedding. A graduated PPR that rises with the magnitude of the reserve shortage would largely correct the over-compensation to these resources.

C. Incentives for Large Units under Pay-for-Performance

As exemplified by the circumstances that caused the first PFP event, large contingencies and forecast errors are likely to continue to be the primary drivers of reserve shortage events. Hence, providing efficient incentives to large resources is particularly important.

Since outages of large resources are likely to be a key driver of shortage events, the performance of large resources, on an average, in most events is likely to be worse than that of the other resources. Therefore, to the extent that the current framework utilizes a higher PPR (relative to the efficient level as determined by the EVOLL curve) during shortage events, larger units are likely to be over-penalized. Furthermore, since a majority of the reserve shortage events are likely to be shallow and prices during such outages could substantially exceed the efficient levels, this issue could result in significant disincentives for large units to continue operations.

Table 5 shows the average availability ("A") of several groups of generators (with a CSO) by type and by size during the September 3, 2018 PFP event. As noted above, this shortage event occurred in part due to the sudden loss of a large resource, and hence, the average availability of resources whose capacity is part of a supply contingency exceeding one GW is lower when compared to smaller resources.

Table 5: Availability by Generator Type and Size
September 3, 2018 PFP Event

<table>
<tr><th>Unit Type/ Size</th><th>< 1 GW</th><th>> 1 GW</th></tr>
<tr><td>Steam Turbine</td><td colspan="2">12%</td></tr>
<tr><td>Combined Cycle</td><td>88%</td><td rowspan="4">77%</td></tr>
<tr><td>Combustion Turbine</td><td>92%</td></tr>
<tr><td>Other</td><td>84%</td></tr>
<tr><td>Wind</td><td>117%</td></tr>
</table>

The table indicates that most categories of generation performed well during the event. Combustion turbines were generally running or providing offline operating reserves, combined cycle units were generally committed and providing energy and spinning reserves, and wind turbines were producing above average. Steam turbines generally performed very poorly because most steam turbines were offline since the event occurred unexpectedly after a large supply contingency.

All generators that are part of a large (>1 GW) contingency are shown separately because an operating reserve shortage is more likely to occur as a result of a large supply contingency. Consequently, a large generator can be expected to have a lower expected A-value than a small generator with an equivalent forced outage rate. As a group, the large generators had a lower average A-value than non-steam turbine units of smaller size. Accordingly, large generators are likely to receive higher PFP penalties and, thus, lower overall capacity revenues than other generators.

There is some increased risk that having large potential supply contingencies increases the likelihood of a load shedding event, and it is appropriate that this risk should lead to some reduction in the capacity revenues of a large generator. However, if the PPR is inflated (relative to the EVOLL) under some circumstances, it may place inefficiently large financial risks on a large generator. Therefore, it would be beneficial to adjust the PPR to be more consistent with the EVOLL.

D. Conclusions and Recommendations

The Pay-for-Performance ("PFP") rules were put in place to enhance incentives for suppliers to perform when they are needed the most. In this section, we evaluate the efficiency of compensation received by suppliers during the event compared to the risk of not serving load and the value of lost load. We also identify misalignment between the compensation for two groups of resources (short-duration energy limited resources and large resources) and their value to the system during reserve shortage events.

The first PFP event in New England occurred for two-and-a-half hours on September 3 during which a shortage of 30-minute reserves ranged up to 880 MW. The shortage resulted primarily from unexpectedly high load (actual load exceeded forecast by ~2.5 GW) and the sudden loss of generation (~1.4 GW). The combination of shortage pricing and PFP incentives led to marginal compensation rates of up to $4700/MWh.

During reserve shortages, prices should rise gradually with the severity of the shortage, reflecting the marginal reliability value of reserves given the size of the shortage level and potential supply contingencies. The marginal reliability value of reserves is equal to the expected value of the load ("EVOLL") that will not be served if the available reserves are reduced by 1 MW. Assuming a $30,000/MWh value of lost load ("VOLL"), we estimated the probability of contingencies that could result in load shedding during the event on September 3. Furthermore, we extrapolated from these data how quickly the EVOLL would have risen after the occurrence of one or more contingencies.

We estimate that the EVOLL ranged from $700 to $1,000 per MWh of operating reserve during the event, far lower than the marginal rate of compensation which ranged from $3000 to $4700 per MWh. However, we find that for shortages of more than 540 MW, the EVOLL would quickly rise above $4700 per MWh up to the assumed VOLL of $30,000 per MWh. This illustrates the deficiencies with the current PPR, which is set at a single value regardless of the magnitude of the shortage. Modulating the PPR based on the reserve shortage level would enhance price formation during reserve shortage events and result in more efficient short and long-run decisions from suppliers.

Interest in battery storage and other energy limited resources has grown quickly in recent years as policy-makers look for non-fossil fuel options for integrating intermittent renewables. However, these resources present special challenges for valuing capacity and energy and operating reserves under shortage conditions. We evaluate the reliability value of a 2-hour battery storage resource and find that such units are likely to be greatly over-compensated for their value under the current capacity market rules, including the PFP compensation provisions. This is troubling as policy-makers and developers prepare to invest heavily in this technology in the coming years.

The FCM rules allow battery storage resources to qualify for 100 percent of their maximum capability, but these resources have significant duration limitations that make them less valuable than most conventional resources when the system is near load shedding conditions. Furthermore, the flexibility of these resources make them likely to perform better under the PFP provisions than most resources during mild to moderate reserve shortage conditions. As discussed above, the marginal compensation rate is far higher than the EVOLL during such reserve shortages, leading battery storage resources to be over-compensated.

We performed a Monte Carlo analysis to estimate the reliability value of a 2-hour battery storage resource for avoiding load shedding and the compensation it would receive in the capacity market. This found that a 2-hour battery storage resource would:

- Have 66 percent of the value of an average conventional resource for avoiding load shedding, and
- Maximize profits by selling 100 percent of their capacity in the FCA and earn 18 percent more in PFP credits.

Furthermore, this significant over-compensation cannot be fixed by reducing the qualified capacity to these resources to an appropriate level (e.g., 66 percent) because this would increase the size of the PFP credit for a combined total of 108 percent of the average conventional resource. A key reason why the PFP construct would over-compensate storage resources is that the PPR is the same for all reserve shortages, regardless of the probability that additional reserves would help avoid load shedding.

In addition, a flat PPR value for all reserve shortages may provide excessive disincentives for large resources to continue operating, since the forced outage of a large resource is more likely to cause a shortage event than the forced outage of a small generator. Hence, the average performance of large resources is expected to be worse than that of the other resources.

Therefore, to the extent that the current framework utilizes a higher PPR (relative to the efficient level as determined by the EVOLL curve) during shortage events, larger units are likely to be over-penalized. Furthermore, since a majority of the reserve shortage events are likely to be shallow, a flat and high PPR could result in significant disincentives for larger units.

A graduated PPR that rises with the magnitude of the reserve shortage would largely correct the issues related to over-/under compensation to battery storage and large resources.

Appendix: Assumptions Used for Key Analyses

A. Evaluation of Pay-for-Performance Pricing

In Section V we evaluated the efficiency of prices during reserve shortage events. We compared the actual/ likely prices against the EVOLL at several levels of depleted ten-minute reserves in multiple scenarios. Our estimated EVOLL reflects an assumed VOLL, and a probability of losing load that we estimated using a Monte Carlo simulation. The simulation incorporates the risk of concurrent generator forced outages, and the potential errors in forecasting renewable generation to estimate the risk of losing load at each reserve level. The key assumptions and methodology for our simulation are as following:

- We assumed the mix of energy and reserve supply in our simulated system to be similar to the actual mix observed during the September 3, 2018 PFP event. We calculated the average contribution of energy and reserves from each resource during the PFP event to develop a representative resource mix for our simulation.
- To simulate depleted reserve levels, we increased the load by an amount corresponding to the decrease in the available reserves. For each given reserve level, we performed 10,000 simulations and determined the number of iterations during which load shedding would occur due to generator outages and forecast errors. We assumed that load shedding would occur when the ten-minute reserve levels drop below 700MW. We calculated the probability of losing load for the given reserve level as the fraction of iterations with load shedding.
- For each iteration, we estimated the aggregate generator forced outage as follows. Each generator was assigned a random number between zero and one. If the assigned random number was less than $1\text{-}e^{(-ORP\ /\ MSTUO)}$, the generator was simulated to be forced out of service. For this analysis, we assumed a two-hour outage recovery period ("ORP"), which is the time needed to fully respond to supply-side contingencies. For each generator, we utilized the NERC GADS database to estimate a class-average Mean Service Time to Unplanned Outage ("MSTUO"). The class-average MSTUO data we assumed is shown in the table below.

Table 6: Mean Service Time to Unplanned Outage by Generator Type

Technology	MSTUO (Hours)
Coal Steam	613
Gas Steam	342
Nuclear	4194
Combustion Turbine	61
Combined Cycle	304
Hydro	459
Others	342

- We assumed the forecast error to be normally distributed with a mean of two percent. Our assumed forecast error distribution is based on the hour-ahead forecast error observed during 2019 in the NYISO footprint.

B. Estimation of Net Revenues for Gas-fired Units

Our net revenues estimates of new and existing gas-fired units are based on the following assumptions:

- Fuel costs for all units are based on the Algonquin City Gates gas price index. We also estimated the net revenues of a new combustion turbine ("CT") based on the Iroquois Zone 2 index.
- All units are scheduled before each day based on day-ahead prices, considering commitment costs, minimum run times, minimum generation levels, and other physical limitations.
- Combined Cycle ("CC") and steam turbine ("ST") units may sell energy, 10-minute spinning reserves, and 30-minute reserves; while combustion turbines (including older gas turbines) may sell energy and 10-minute or 30-minute non-spinning reserves. Each unit is assumed to offer reserves, limited only by its ramp rate, minimum down time and commitment status.
- Combustion turbines are committed in real-time based on hourly real-time prices. Combustion turbines settle with the ISO according to real-time market prices and the deviation from their day-ahead schedule.
- Online units are dispatched in real-time consistent with the hourly integrated real-time LBMP and settle with the ISO on the deviation from their day-ahead schedule. However, to account for the effect of the slower ramp rate of the ST unit in this hourly analysis, the unit is assumed to operate within a certain margin of the day-ahead energy schedule. The margin is assumed to be 25 percent of the maximum capability.
- Combustion turbines are also evaluated for their profitability based on the generator's decision to participate in the Forward Reserve Auctions for each of the capability periods.[43] It is assumed that generators anticipate when selling forward reserves will be more profitable than selling real-time reserves before each capability period.
- The net revenues from capability year 2020/21 to 2023/24 are based on the forward prices for power, natural gas, ULSD and FCA clearing prices.[44]
- Fuel costs assume transportation and other charges of 27 cents/MMbtu for gas and \$2/MMbtu for oil on top of the day-ahead index price. Intraday gas purchases are

43 We assume that the combustion turbines are capable of providing only the 30-minute reserve product in both the Forward Reserves Market and the Real-Time Reserves Market. We scaled down the forward reserve revenues earned by individual units using the ratio of (a) the capacity of 30-minute capable resources that offered into the most recent FRA, and (b) the total existing capacity of 30-minute resources.

44 We utilized the average of forward prices over the trading period of 01/012020 through 04/30/2020.

assumed to be at a 20% premium due to gas market illiquidity and balancing charges, while intraday gas sales are assumed to be at a 20% discount for these reasons. Regional Greenhouse Gas Initiative (RGGI) compliance costs are included.

- The minimum generation level is 152 MW for CCs and 90 MW for ST units. The heat rate is 8,000 btu/kWh at the minimum output level for CCs, and 13,000 btu/kWh for ST units. The heat rate and capacity for a unit on a given day are assumed to vary linearly between the summer values on August 1 and the winter values on February 1.
- The PFP-related penalties and payments for each of the unit types are based on the average performance of the given type of unit during the September 3, 2018 PFP event, the scheduled PPR value, and the number of scarcity hours corresponding to the cleared capacity for the Capability Year.
- The ESI-related changes to net revenues of each unit type are also included from 2024/25 onwards for the purpose of estimating the after-tax IRRs shown in Figure 9.
- The assumed operating parameters for all gas-fired units are shown in Table 7.

Table 7: Unit Parameters for Net Revenue Estimates of Gas-fired Units

Characteristics	CT - 7HA	CC 1x1	ST	GT-30
Summer Capacity (MW)	331	283	360	16
Winter Capacity (MW)	345	297	360	20
Heat Rate (Btu/kWh)	9,220	7,750	9,500	17,000
Min Run Time (hrs)	1	4	16	1
Variable O&M ($/MWh)	$1.1	$5.0	$9.9	$6.0
Startup Cost ($)	$17,200	$1,000	$6,507	$562
Startup Cost (MMBTU)	510	1,800	3,500	60

C. Estimation of Net Revenues for Renewable Resources

We estimated the net revenues the markets would have provided to utility-scale solar PV, onshore wind plants, and offshore wind plants in ISO-NE using the following assumptions:

- Net E&AS revenues are calculated using real time energy prices.
- The energy produced by these units is calculated using technology and location-specific hourly capacity factors for each month. The capacity factors are based on location-specific resource availability and technology performance data from NREL.
- The capacity revenues for solar PV, onshore wind plants and offshore wind plants in every year are calculated using prices from the corresponding FCAs. The capacity values

of solar PV, onshore wind and offshore wind plants are based on the average ratio of qualified capacity to the nameplate rating (16, 30 and 45 percent, respectively).[45]

- Solar PV and onshore wind plants, as renewable projects, are eligible for Investment Tax Credit ("ITC") and Production Tax Credit ("PTC") respectively as part of federal programs to encourage renewable generation. The ITC reduces the federal income tax of the investors in the first year of the project's commercial operation. The PTC is a per-kWh tax credit for the electricity produced by a wind facility over a period of 10 years. We assume ITC and PTC levels consistent with units commencing construction in 2020.
- We estimated the value of RECs produced by utility-scale solar PV and onshore wind using the January 2020 through April 2020 average of the MA Class I REC Index values ($36.70/ MWh) from S&P Global Market Intelligence. We estimated the implied REC price for offshore wind units using the contract price from the Vineyard Wind PPA and the forward energy prices.
- Table 8 shows the assumed costs and operating parameters of the renewable units we studied. The data shown are based on cost and regional multipliers from NREL.[46]

Table 8: Utility-Scale Solar and Onshore Wind Parameters for Net Revenue Estimates

Parameter	Utility-Scale Solar PV	Onshore Wind	Offshore Wind
Investment Cost (2024$/kW AC basis)	$1,609	Massachusetts: $2428 Maine: $2344	$3,748
Fixed O&M ($/kW-yr)	$16	$47	$108
Federal Incentives	ITC	PTC	ITC
Project Life	20 years		25 years
Depreciation Schedule	5-years MACRS		
Average Annual Capacity Factor	17%	Massachusetts: 35% Maine: 42%	50%

D. Estimation of Net Revenues for Battery Storage Resources

We estimated the net revenues ISO-NE markets would have provided to a 2-hour battery storage resource during March 2017 through February 2020 based on a storage dispatch model that utilizes the following assumptions:

- The hourly net revenues are determined using the real-time energy and ten-minute spin prices, and the resource's output as determined by its charge and discharge offers.

45 The solar and onshore wind capacity values are from the most recent CONE and ORTP study. Capacity value for offshore wind is based on data from *Northeast Offshore Wind Regional Market Characterization* report by Sustainable Energy Advantage, LLC, 2017.

46 See NREL's 2019, *Annual Technology Baseline*, See https://atb.nrel.gov/electricity/2019/data.html. Regional multipliers are from inputs to NREL's ReEDS modeling analyses.

- The resource's hourly charge and discharge offers in the real-time market are each the product of two components: a) the minimum (for charging) or maximum (for discharging) of the forecasted hourly CTS and DA prices for the remainder of the day, and b) an empirically estimated adjustment factor.
- The battery storage operator continuously updates a forecast of the minimum and maximum prices over the remainder of the day based on: (a) price forecasts published for the Coordinated Transaction Scheduling ("CTS") process between ISO-NE and the NYISO, which look ahead 150 minutes, and (b) prices from the day-ahead market.
- For all hours in a given month, we set the adjustment factors to equal the values that maximized profits in the prior month.[47] Our model uses separate adjustment factors for charge and discharge offers.
- If the battery's state of charge as determined by the charge offers is not 100 percent by hour 15 in winter months and hour 4 in summer months, we assume that the battery will charge fully in hours 15 and 16 (winter) or hours 4 and 5 (summer) regardless of the price forecast. Similarly, we assumed that the battery will be discharged completely by hours 19-20 on all days.
- Table 9 summarizes our assumptions for cost and operating parameters.[48]

Table 9: Energy Storage Parameters for Net Revenue Estimates

Parameter	
Investment Cost (2024$/kW)	*Mid -* $851, *Low - $666*
Fixed O&M ($/kW-yr)	*Mid -* $21, *Low - $17*
Round-Trip Efficiency (%)	86%
Project Life	20 years
Property Tax	1.00%
Depreciation Schedule	7-year MACRS

47 For example, if the battery storage resource would have maximized EAS net revenues in the previous month by offering to sell energy at 130 percent of the forecasted maximum price, the resource will submit energy offers in the current month at 130 percent of the forecasted maximum price.

48 Our assumed battery costs are derived from NREL's 2019 Annual Technology Baseline. See https://atb.nrel.gov/electricity/2019/. We estimated the costs of a 2-hour resource by adjusting the NREL-reported costs of a 4-hour resource. Our cost adjustment is based on the ratio of the capital costs of 2-hour and 4-hour battery resources from a 2018 NYSERDA study. See https://www.ethree.com/wp-content/uploads/2018/06/NYS-Energy-Storage-Roadmap-6.21.2018.pdf. We also incorporated a regional cost multiplier to estimate the costs of developing a 2-hour resource in New England. See https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf.